SUBMISSION

TO THE

ROYAL COMMISSION ON ENERGY

CALGARY, ALBERTA

FEBRUARY, 1958

CANADIAN WESTERN NATURAL GAS CO. LTD.
CALGARY, ALBERTA

NORTHWESTERN UTILITIES, LIMITED
EDMONTON, ALBERTA

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Exhibit no. C-10-1

QUALIFICATIONS OF CARL ALVIN TREXEL JR.

Academic Background

Bachelor of Science degree in Chemical Engineering, Massachusetts Institute of Technology.
M.B.A. degree in Business Administration from the University of California.

Prior to 1953 employed by Shell Chemical Corporation as a technologist.

Has been with Stanford Research Institute since 1953. Present position is Senior Energy Economist and head of the Energy Economics Section.

QUALIFICATIONS OF BRUCE FRANKLIN WILLSON

Born in Edmonton.

Graduated from the University of Alberta in 1943 with Bachelor of Science degree in Civil Engineering.

Commenced employment with Northwestern Utilities, Limited, Edmonton, as Distribution Engineer in November 1945.

Appointed Vice-President Operations for Northwestern Utilities, Limited and Canadian Western Natural Gas Company Limited, December 1956.

Director of Northwestern and Canadian Western, and Alberta Gas Trunk Line Limited.

Exhibit C-10-1.

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Henry Borden

SUBMISSION OF

Canadian Western Natural Gas Company Limited
(Canadian Western)

and

Northwestern Utilities, Limited
(Northwestern)

TO

THE ROYAL COMMISSION ON ENERGY

Presented By

D. K. Yorath, President

SUBMISSION OF

Canadian Western Natural Gas Company Limited
(Canadian Western)

and

Northwestern Utilities, Limited
(Northwestern)

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THE ROYAL COMMISSION ON ENERGY

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D. K. Yorath, President

I

INTRODUCTION

1. The companies I represent are pleased to present to the Commission the benefit of their experience over nearly 50 years as producers, transmitters and distributors of natural gas within the Province of Alberta and also their views as to how the present and future gas supply problems of Alberta consumers can be solved.

In 1957, the companies served approximately 145,000 consumers and distributed over 83 billion cubic feet of gas, with a potential peak day demand this winter of 560 million cubic feet. As will be indicated later, the companies anticipate that within 30 years their customers will require 268 billion cubic feet annually at a maximum daily rate of 1,650 million cubic feet.

Not only do these companies produce, transmit and distribute natural gas but they do all their own construction work. This has been the practice of these companies for many years; it has resulted in substantial savings to gas consumers in the province and is not a usual practice among gas utilities.

2. The companies would like at the outset to emphasize the fact that their business interests and the interests of the consumers of natural gas in Alberta coincide. Only by supplying the requirements of such consumers in adequate quantities and at the lowest possible prices can these interests be served.

3. It will be seen that this brief comprises matters of general information and policy as well as technical and economic matters. Questions on the former may be addressed to me. Questions on technical and economic matters may be addressed to Mr. B. F. Willson, the vice-president in charge of operations for the two companies.

II

HISTORY OF THE COMPANIES

4. (a) Canadian Western was incorporated under the laws of Alberta in 1911, under the name of Canadian Western Natural Gas, Light, Heat and Power Company Limited and its name was changed in 1947 to Canadian Western Natural Gas Company Limited. The company distributes natural gas for domestic, commercial and industrial use in the southern part of the Province of Alberta, and serves a population of approximately 281,000; practically all of whom are dependent on natural gas for heating.

The company's area of service comprises the Cities of Calgary and Lethbridge and 49 other communities. Distribution is carried out under various franchises and by-laws of the respective communities or, in the case of unincorporated communities, under orders of the Board of Public Utility Commissioners for the Province of Alberta. Since the discovery in Alberta of natural gas in marketable quantities, the company and its associate, Northwestern, have been its leading distributors within the province.

(b) The company's supply of natural gas is obtained principally by purchase from Madison Natural Gas Company Limited in the Turner Valley field and from Shell Oil Company of Canada Limited in the Jumping Pound field.

Natural gas produced in the Fenn Big Valley and Stettler fields is purchased from the British American Oil Company Limited and provides a supply for the company's system between Red Deer and Calgary. The company owns small reserve fields at Bow Island and Foremost upon which it draws to supply winter peak requirements of the system. The location of the various fields referred to above may be seen by reference to the map found on Page 7 under Tab A.

5. (a) Northwestern was incorporated in 1923 and is engaged in the business of the production, transmission and distribution of natural gas in Central Alberta. Its principal market is the City of Edmonton, but it serves in addition 56 other communities, including the Cities of Red Deer, Camrose and Wetaskiwin, and a large number of towns, villages and hamlets. The population of the area served by the company is 320,000, practically all of whom, as in the case of Canadian Western, depend on natural gas for heat.

The location of the various communities served by this company may be seen by referring to the map found on Page 7 under Tab A.

(b) For many years the principal source of the company's gas supply was the Viking-Kinsella field, located approximately 80 miles southeast of Edmonton. In recent years the company has undertaken exploration and development work in areas north and northeast of Edmonton and has established important reserves of dry gas which are of considerable assistance in meeting the maximum demand of the company's system. These newly developed reserves, together with gas from the Viking-Kinsella field are principally owned or controlled by the company. Since 1950, solution gas produced in conjunction with crude oil in the Edmonton area has become available in increasing quantities, and now supplies an important part of the company's market. Due to the fact that this gas is produced unavoidably with oil, the company as a conservation measure, to the fullest extent possible, gives priority to the purchasing and marketing of this solution gas.

The company has contracts to purchase oilfield gas from the Leduc, Bonnie Glen, Acheson and Samson fields located in the Edmonton area.

A drilling program in the Beaverhill Lake area 40 miles southeast of Edmonton, and adjacent to the company's four transmission lines from the Viking field resulted in the proving up of substantial reserves of dry, sweet natural gas. The company recently acquired 8,600 acres of proven gas reserves in the Westlock field, shown as the Picardville field on Page 7 of Tab A where the location of the various fields referred to above may be seen.

III
GROWTH OF THE SYSTEMS

6. The growth of the systems can best be presented by referring to the six maps shown as Pages 1 to 6 under Tab A. In these maps the systems as they existed in various years are set forth. The fields shown on these maps are the principal fields of interest to the companies which were known to exist in the various years noted.

Page 1 under Tab A illustrates Canadian Western system as it existed in 1913 with a line 170 miles in length and of 16-inch diameter, connecting the Bow Island field to Calgary, with branch lines serving the City of Lethbridge and other communities en route. It also shows the Town of Brooks served by a field immediately adjacent to that community. It will be noted that no pipeline system is shown in the area now served by Northwestern, which company was not in existence in 1913.

Page 2 under Tab A shows the Northwestern transmission line which was connected in 1923 comprising 78 miles of 10-inch and 12-inch diameter, connecting the Viking field to the City of Edmonton. The only change with respect to Canadian Western since 1913 was the construction of a six-inch line tying in the Turner Valley field at a point just south of Okotoks.

Page 3 under Tab A shows the changes that took place in the 10-year period 1923 to 1933. Referring to the Northwestern area the only significant transmission development was the commencement in 1929 of a second pipeline from the Viking field to Edmonton. This line 12 inches in diameter, had by 1933 reached a point near Ryley and was tied into the existing line at that point.

The Canadian Western system was added to by the construction of two additional lines to Turner Valley, one of 10-inch and the other of 14-inch diameter. At the southeastern terminus of the Canadian Western system the map shows the connecting of the Foremost field to the company's main transmission system at Bow Island.

Page 4 under Tab A shows that in the ten years 1933 to 1943, the Northwestern system was extended from the Viking field southeast to the Kinsella field, the whole area now being considered as one field under the name of Viking-Kinsella. It also shows an extension from Northwestern's main transmission line to the Town of Vegreville. The second line previously referred to from Viking-Kinsella was continued from Ryley into Edmonton in 1943. In these ten years there was no change in the transmission line system of Canadian Western.

Page 5 under Tab A shows that in the 10-year period preceding 1953 the growth of both companies was substantially accelerated. In Northwestern a line was extended to the City of Red Deer, serving it and communities en route. The Leduc-Woodbend field was connected to the system as were the fields of Fort Saskatchewan and Bon Accord. The company acquired the Vermilion distribution system which was served with inadequate supplies from the Wildmere field. Because of the inadequacy of these supplies, Vermilion was connected to the Viking-Kinsella field. In addition, service was extended to other communities as shown on the map. During this period a third line from Viking to Edmonton was completed and about 40 miles of a fourth line built, both of these lines being of 16-inch diameter.

In Canadian Western, during this period, the Jumping Pound field was tied into the main transmission line south of Calgary by a 12-inch line, and service was extended westward from this field to serve a large cement plant at Exshaw, the Town of Banff and other communities en route. The main transmission system was looped south from the City of Calgary with a second 16-inch line as far as the junction of the 14-inch Turner Valley line and a cross-tie constructed from the 10-inch Turner Valley line. A well in the Princess-Brooks field, six miles northeast of Brooks, was tied in to the town system to reinforce the gas supply there.

<u>Page 6 under Tab A</u> - Between 1954 and 1957, the Northwestern system was extended to serve various communities. An extension from Vermilion to Lloydminster was built to reinforce the gas supply in the Lloydminster area. Looking at the map and coming west, the next extension is from the Viking-Kinsella field to serve four communities immediately north. The next extension was a system built from the Beaverhill Lake field to serve five communities north of that area. A line was built west of the City of Edmonton to the Acheson field, connecting that field to the system and serving two communities west of Acheson. A 45-mile, 12-inch line was built from the Bonnie Glen field to the City of Edmonton to provide a market for oilfield gas. Service was extended to several communities west of Edmonton, as shown on the map. The company purchases the necessary gas supplies for these communities from a pipeline owned by North Canadian Oils Limited, which was built to serve the pulp mill at Hinton.

Canadian Western extended its system south from the City of Red Deer to Airdrie, serving communities en route. It also extended its system south of the City of Lethbridge to serve six communities in that section of the province.

Page 7 under Tab A is a map showing the systems of the companies and their proposed pipeline construction for 1958, the most important of which are Northwestern's line from the Pembina field to Edmonton, and Canadian Western's line from the Carbon field to Calgary.

7. The growth of the companies is further shown by reference to the sales of the product and to the number of customers. These particulars are given on Pages 1 and 2 of each of the Tabs B, C, D and E. These pages show the sales and number of customers year by year and selecting years, roughly ten years apart, may be tabulated as follows:

Canadian Western

Year	Customers	MCF Sales
1916	8,844	3,645,587
1923	11,752	1,915,683
1933	22,236	6,694,855
1943	26,926	10,828,386
1953	54,690	28,313,300
1957	73,624	37,601,442

Northwestern Utilities

Year	Customers	MCF Sales
1925	6,247	1,548,965
1933	10,478	2,745,546
1943	15,974	6,490,981
1953	55,698	25,711,569
1957	76,520	46,266,411

Pages 1 and 2 under Tab F show the gas consumption per capita of the two systems. The significant increase which has occurred indicates that the growth of system sales is attributable not only to the gain in population served by each system but also to a greater use of gas by individual users.

IV

TYPES OF GAS

8. The natural gas obtained from the various fields referred to in Part II above is of the following types:

(A) Dry, sweet gas -- This type is usually found at relatively shallow horizons and at relatively low pressure with the result that the wells are cheaper and in most cases the only processing required is the removal of sufficient water vapor to make the gas transportable.

(B) Sour and condensate field gas -- Sour gas contains sulphur compounds. Gas from the condensate fields is usually sour and also contains varying amounts of hydrocarbons which are recoverable from the gas as liquids. Gas in this category is usually found at greater depth and at higher pressures than dry, sweet gas, consequently the wells are more expensive and in order to make the gas marketable processing plants are required to remove any sulphur or condensable hydrocarbons.

(C) Associated gas -- Associated gas falls into two categories:

(i) Gas which is in solution in the reservoir with the crude oil and which is produced with the oil at the time and place of the oil production itself, and

(ii) Gas which forms a gas cap overlying the oil reservoir.

Both types of associated gas have characteristics similar to condensate field gas. As a result, processing is required both to separate the gas from the oil and other hydrocarbons and also to remove sulphur from the gas.

Normally gas cap gas must be left in place until the oil reservoir is depleted to the maximum amount possible since it is the pressure of the gas cap on the oil column which provides the energy to produce the oil.

V

GAS RATES

9. The chart found on Page 2 under Tab G shows the Dominion Bureau of Statistics Consumer Price Index over the period 1939 to 1957 as compared with the average domestic gas prices over that period for the two systems.

The chart shows that the average domestic prices have remained relatively stable during a period when consumer prices have risen over 90 per cent.

The rate history of the companies upon which the chart just referred to is based will be found on Pages 1 and 2 under Tabs H and I for Canadian Western and on Pages 1 and 2 under Tabs J and K for Northwestern.

The current rate schedules prevailing in the two companies are shown under Tabs L and M.

The present policy of Canadian Western and Northwestern with respect to gas rates is a "cost of service" approach consistent with the formula for allowable revenues adopted by the Board of Public Utility Commissioners

of Alberta. It is of course recognized that there are other valid approaches to the determination of rates, depending on such varying circumstances as the price of competitive fuels and the consumer's ability to pay. However, the companies have been for many years in a somewhat unique position in that their rates for the greater part of the service area have been well below comparable prices of competitive fuels. This is due to the proximity of markets to sources of gas supply and to the construction of major portions of the present production, transmission and distribution facilities at cost levels substantially below those of the present day. This also accounts for the fact that gas rates in the major portions of the companies' systems are the lowest on the continent, with only one or two minor exceptions.

Costs on the companies' systems are determined for various classifications of service depending upon volume of annual use and the relationship between average daily use over the year and peak day demand, that is load factor. This is accomplished by means of a detailed cost analysis from which an appropriate portion of each element of cost in the board's formula for allowable revenue is allocated to each classification. Rates are then set to yield revenues equal to the total of such costs as closely as practicable.

In the period of rapidly rising costs, during and subsequent to World War II, service has been extended by the companies to a large number of additional communities. In these cases, because of such increased costs, rates in effect on the original systems would not have yielded the costs of service for the required facilities. Higher rates have therefore been established and a cost of service approach has been made in setting such rates.

In the higher rate areas served by the companies, gas rates are closely competitive with comparable coal prices and in certain cases exceed them somewhat although still well below the comparable prices of fuel oil or propane. Nevertheless, almost the entire potential market has been obtained due to other advantages of natural gas as a fuel. Some of these advantages are cleanliness, ease of control, lower equipment maintenance and the avoidance of fuel and ash handling.

VI

LOAD FACTOR

10. To appreciate fully the role played by the various types of gas supply mentioned under Section IV and the importance of each in combining to serve a particular market, it is necessary at this time to go into the matter of load factor.

Since gas cannot be stored on consumers' premises and yet must be available when needed, it is necessary that the utility provide production, transmission and distribution facilities of sufficient capacity to supply the maximum coincident demand (peak demand) of all its customers. In Alberta, it has been found that the maximum potential daily demand is reached when the average temperature falls to 40 degrees below zero, or lower. Since weather of this severity occurs infrequently it follows that the companies' facilities are used to capacity on only rare occasions. The average daily throughput during the year is of course much less than that

which is handled on the severe day referred to above. The relationship between the average daily quantity consumed throughout the year and the maximum potential daily demand for that year is referred to as the annual load factor of the companies' systems.

On the graph under Tab N the daily sales of gas by Northwestern are plotted for the year 1957. It will be noted that on February 21 the daily sales were at a maximum and amounted to 257 million cubic feet, while on August 18 the daily sales fell to 48 million cubic feet. It will also be noted that the daily sales vary widely throughout the year. The horizontal line represents the average sales per day throughout the year which was 123.5 million cubic feet. The annual load factor of Northwestern during 1957 was therefore $\frac{123.5 \text{ (average daily sales)}}{257 \text{ (peak day sales)}} \times 100 = 48\%$.

It should be pointed out that during this year the coldest day had an average temperature of only 15 degrees below zero. The peak would have been much higher than the 257 million cubic feet above referred to had more severe weather conditions been encountered. The utility has to plan for the worst conditions even though they do not materialize in any one year. The potential peak day demand on Northwestern's system in 1957 was 321 million cubic feet and if that demand had been incurred the load factor would have been $\frac{123.5 \text{ (average daily sales)}}{321 \text{ (peak day sales)}} \times 100 = 38.5\%$

The capital investment of a utility is very high relative to its annual gross income. Fixed charges represent a large portion of its annual fixed costs and since those annual fixed costs must be spread over the amount of gas sold during the year the fixed costs per unit will vary

inversely with the load factor. For example, if a processing plant designed to deliver 100 Mcf of gas per day is operated at 100 per cent load factor it will deliver 36,500 Mcf in a year. If, on the other hand, it is operated at only 40 per cent load factor it will deliver only 14,600 Mcf during the year. In the first case, the fixed charges are spread over 36,500 Mcf and in the latter they can be spread over only 14,600 Mcf resulting in unit fixed costs two and a half times as great as in the case of 100 per cent load factor. The same principles apply to the costs of transmission and distribution.

A very large percentage of the natural gas consumed in Alberta is used for space heating. Consequently, the demand varies inversely with the temperature. In Alberta there is a very large variation in the daily temperatures throughout the year. The graph under Tab N illustrates how frequently and extensively the demand varies over the year.

This low load factor pattern will continue as the local market grows unless such growth is accompanied by a greater proportion of industrial sales and possibly a marked increase in the use of gas for summer air conditioning. If the proportion of industrial sales (which vary only slightly with temperature) decreases, the load factor will worsen.

Frequent sharp variations in peak demand can be best handled by dry, sweet gas fields, the production from which is flexible. Their production can be adjusted much more easily and quickly than the output of a processing plant. While the peak demands are large they are usually of short duration so that the annual amount of gas required to handle them is small.

Consequently, the load factor on such a field is very low. Again, dry, sweet gas sources are most desirable to meet these peak demands because the investment is relatively low and the effect of poor load factor on unit costs is minimized.

If suitable reservoirs are available gas can be taken from the less flexible sources during the summer time and injected into these reservoirs for reproduction during periods of peak demand. For this purpose, dry, sweet gas fields which have been partially depleted are the most suitable. If dry, sweet gas is reinjected into a reservoir which has contained sour gas and other hydrocarbons, it becomes contaminated by the residual impurities left in the reservoir and has to be repurified when reproduced.

In most instances, heating or processing equipment of large customers, more particularly industrial consumers, can be equipped to burn either gas or oil. Where this is the case, a rapid switch-over from one fuel to the other can be made and oil used during periods when there is a large demand for gas. This is known as peak shaving and is common practice in certain localities where the cost of oil is not substantially higher than gas so that the cost of gas plus oil is still more economical than oil alone or any other fuel.

Where this practice prevails, gas service is provided at lower rates than that provided to firm customers. This special type of service is known as interruptible, that is to say, in periods of peak demand the supply to such customers may be curtailed or discontinued.

However, in Alberta, oil is considerably more expensive than gas and if a customer were asked to switch to oil for any length of time the cost of gas plus oil could exceed the cost of using coal. Consequently, this particular method is not very practical in Alberta.

Peak load sources and summer storage do not improve the load factor of the market. However, they do improve the load factor which can be offered to fields with a high investment where a high load factor is essential to economic operation. They concentrate the impact of poor load factor on the peak load sources where it has the least effect on total costs. If a suitable storage reservoir can be obtained close to the market it also improves the load factor on the transmission lines.

VII

PRESENT SUPPLY AND PLANS FOR IMMEDIATE FUTURE

11. While the Canadian Western system is presently connected to reserves of sufficient size to supply base load requirements for 20 years at the present rate of annual consumption, a new source of peak gas must be obtained immediately. Statement 3 under Tab O shows the estimated future peak day requirements and annual sales until 1986. On the basis of these estimates, the peak day demand will exceed the maximum deliverability of the presently connected sources by the winter of 1958-59. To take care of this situation the company plans to connect during 1958 the Carbon field located about 50 miles northeast of Calgary. This is a dry, sweet gas

field with high deliverability and will be used to supply peak loads. Eventually it will be used for storage as well.

In addition to obtaining additional gas to supply peak loads, the company must look ahead and plan for additional substantial reserves for future use. It is anticipated that a processing plant will be completed in the Okotoks field early in 1959 and that the residue gas from this plant will be used to help meet growing demands. Canadian Western's market is continuing to develop but unfortunately the load factor is not improving. For this reason, it is imperative that a peaking source such as Carbon be connected. As a further indication of the flexibility of dry, sweet gas sources, it may be pointed out that, if necessary, by taking from that field more gas than is actually required for peaking, the company will be able to meet its market requirements until sufficient base load has been developed to warrant the construction of a purification plant at one of the sour fields. If this is done, the additional gas taken out of Carbon can be replaced by repressuring during summer months.

Northwestern's system is presently connected to substantial dry, sweet gas fields which are capable of meeting peak demands for the next few years. (See Tab P, page 3). However, these dry, sweet gas fields are being used to supply a large amount of base load gas,

causing their pressure to decline and their deliverability to diminish. It is therefore necessary for Northwestern to gain access to large base load reserves and thus enable it to preserve the deliverability of the dry, sweet gas fields for peaking purposes. Northwestern plans to build during 1958 a transmission line to the Pembina oil field located about 70 miles west of Edmonton and take delivery of residue gas estimated to amount to 65 million cubic feet per day. As much Pembina gas as possible will be sold to Northwestern's customers and the balance stored in the Viking-Kinsella gas reservoir. In view of the importance of adequate dry, sweet gas sources serving a low load factor market, Northwestern last year purchased a substantial interest in the Westlock gas field some 50 miles northwest of Edmonton.

VIII

THE PROBLEM OF ALBERTA'S LONG TERM SUPPLY AND COST OF GAS

12. The major problem confronting the companies today is that of ensuring adequate future supplies of natural gas at prices or costs which have a minimum financial impact on consumers. This is a difficult problem because of the low load factor of their demands and the necessity of maintaining deliverability for the future. It must be solved within a framework which takes into account the following factors:

(a) The necessity to keep the retail rates for natural gas as low as possible in order to compete successfully with other low-cost fuels, principally coal.

(b) A recognition of Alberta's present difficulty in attracting industry and the desirability of retaining for the province the advantage of low cost gas supplies.

(c) The low annual load factor of the Alberta utility market and hence the necessity of the companies themselves developing their own sources of peaking gas.

(d) The high unit cost of peak load gas resulting from its production on such a low load factor.

(e) The very sizable future gas requirements and the relatively small present market over which to spread present day costs associated with meeting these future requirements.

(f) The necessity of paying a price for natural gas which enables the producer to recover his costs, including a reasonable return on his capital investment.

(g) The importance to the economy of the province of a healthy oil and gas exploration and producing industry and the need for reasonable incentives to maintain it.

(h) A recognition that local markets for natural gas are limited at the present time, and that export from the Province is necessary in order to provide adequate market outlets.

(i) The likelihood that the ultimate proven reserves of Alberta will be at least the 75 trillion cubic feet postulated by the Oil and Gas Conservation Board in its report of January 31st, 1957.

It is within the framework of these factors that the Alberta utility companies have sought to solve the problem of ensuring the future gas requirements of the province at prices no higher than are necessary to provide the required volumes of gas. Possibly an elaboration on each of these factors would be helpful to the Commission in its understanding of the local situation.

(a) The Effect of Competitive Fuel Prices on the Future Demand for Natural Gas

Under Tab R is a report prepared by the Stanford Research Institute of Menlo Park, California, at the request of Northwestern and Canadian Western. The companies have been concerned for some time lest rising field prices of natural gas, coupled with other increases in costs, result in natural gas losing its place as the lowest cost fuel for industry in the province. At the present time, industrial natural gas rates are such that in most locations gas undersells coal and other fuels.

With this competitive fuel problem in mind, the companies retained the Institute to prepare an estimate of the future demand for natural gas in the province and to assess the impact of this demand on industrial growth. This report was completed in August of 1957. Distribution has not been widespread to date.

The report looks into the future as far as 1970. It estimates the demand for natural gas in the market area of the two utility companies for the year 1970 to be 172.4 billion cubic feet. This is slightly less than the companies' estimates for the same year of 177.7 billion cubic feet. (See table on page 12 of the Report, Tab R).

The Conservation Board in its estimates of the future provincial gas requirements has prepared them on a province-wide basis rather than on that of the areas served by the two companies. The Institute's estimate for the total provincial requirements for the year 1970 is 222 billion cubic feet as compared with the Board's estimate of 257 billion cubic feet.

Broadly speaking, the Institute has estimated the provincial domestic and commercial requirements at somewhat higher levels than the Conservation Board and the companies, due to larger estimates of population growth. However, its estimate of gas for industrial use is substantially less than those of the Board and the companies. The reasoning behind their estimates is set out in the report. It would appear that one of the major reasons for the substantially lower estimates for industrial use lies in the consideration given in the Report to the competitive fuel situation.

A representative of the Institute is available to be called as a witness.

The companies in formulating their policy for long-range supply have had to keep in mind the fact that coal from Alberta's vast reserves can be delivered to industrial markets in some instances at prices equivalent to natural gas at 12¢ per Mcf. Since it appears likely that in the future gas cannot be developed, gathered and processed for less than 12¢ per Mcf, it follows that in certain cases at least coal will supplant natural gas. The threat of competition from other fuels causes a great deal of concern to the companies in that if they are to lose their industrial markets, the fair share of system costs presently borne by industrial consumers will have to be carried by the domestic and commercial users and this can only result in further increases in domestic and commercial gas rates.

(b) Attracting Industry to Alberta

Alberta with its relatively small local markets and the distance it is located from the larger national markets, needs every advantage it can obtain in order to attract new industry and thus stabilize the economic base of the province. One advantage it has had to date has been low industrial gas rates. This has been due largely to the development of shallow gas supplies at cost levels considerably below those of today. Present high cost levels will of necessity result in increased industrial gas rates. In order to attract industry to Alberta it is necessary to keep industrial gas rates as low as possible.

(c) <u>The Low Annual Load Factor of Alberta Markets</u>

As is shown in the 30-year projection of market requirements (Statements 3 and 6 under Tab O), the annual load factor of the companies' markets is about 40%. Because supplies from oilfield operations and condensate fields are purchased at load factors of 70% and higher, it is necessary to provide peaking facilities to transform the total supply to a 40% load factor pattern. As a result these peaking facilities have to operate on load factors of 20% and less. Since this is not an attractive type of market to a gas producer, the companies have found it necessary to develop these facilities themselves.

(d) <u>Cost of Peak Load Gas</u>

Because of the low annual use made of peaking facilities, the total costs, both fixed and operating, must be spread over a relatively small number of units. This can result in very high unit production costs. (See Tab Q). In determining its policy with respect to acquiring additional supplies, the companies must keep in mind the burden of costs associated with peak load facilities.

(e) <u>A Large Future Market Compared with a Relatively Small Present Market</u>

It has been suggested that the companies should acquire sufficient gas in the ground at this time to take care of their long-term requirements. The estimated recoverable reserves of fields presently connected to the transmission lines are slightly over 3 trillion cubic feet. As noted in Statement 7 under Tab O the companies estimate their 30-year market requirements to be about 5.4 trillion cubic feet. In order to ensure deliverability in the thirtieth

year, another 1.5 trillion cubic feet undoubtedly would be necessary. Therefore, to have under control sufficient proven reserves to take care of the 30-year requirements, the companies would have to acquire today an additional 4 trillion cubic feet.

Assuming this gas could be acquired at 2.5¢ per Mcf in the ground, an immediate expenditure of about $100 million would have to be made. Since the fixed charges on this investment would have to be borne by present day consumers, it has been calculated that even if the project were financially feasible, existing rates would have to be increased by more than 60 per cent just to take care of the annual costs associated with an expenditure of this magnitude. If supplies are acquired from time to time as required in the future and as justified by market growth, then the impact at any particular time will be much less.

(f) Price to Producers

It is clear that the gas producing industry will not explore for and develop the province's gas reserves unless an adequate financial return will be realized. The history of the industry in this province has demonstrated that the money required for the development of gas reserves must compete with the crude oil side of the industry and it is logical that oil companies will not spend the many millions of dollars necessary to develop natural gas reserves unless the return is reasonably comparable to that which would be earned by those same dollars spent in the development of crude oil. Since the purchasing power of the dollar is much less today than it was ten years ago, it follows that the costs of acquiring land, exploration

and development, are such today that the unit selling price for pipe line gas must be higher than prices which were fixed in the 1940's and early 1950's. Canadian Western pays 10-3/4¢ per Mcf for gas purchased from the Turner Valley and Jumping Pound fields. These prices were fixed in 1948 and 1951 respectively. It is not likely that Canadian Western will be able to contract for comparable supplies developed under 1958 cost levels at the same price as in its Turner Valley and Jumping Pound contracts.

The possibility exists that if gas prices were such that the returns to the gas producer were comparable to those of the crude oil producer then greater effort would go into the exploration and development of natural gas reserves. A more intensive exploration program for gas only should have the result of proving up substantially larger reserves than would result from a program geared to a less intensive exploration activity. Assuming the demand for natural gas is the same in both cases, an increase in available supplies should result in greater long term stability of price than would result from bargaining in the future for gas in shorter supply.

(g) <u>The Necessity to Meet the Problem Without Confiscating the Capital of Others</u>

It has also been suggested that the provincial authorities be asked to set aside and immobilize certain proven reserves in order to be sure that the 30-year requirements of the province are taken care of before additional export is permitted. This presumably would involve the arbitrary selection of certain fields. The owners of those fields would have to be told that they could not offer their gas to potential purchasers, but rather that their

reserves would have to be shut in for use at some indefinite future time t be used within the province. This would amount to confiscation of capital.

The dangers inherent in such a situation are obvious. The companies do not consider this to be a reasonable or proper way of providing for the future gas requirements of the province. This country has progressed under a free enterprise system whereby resources have been developed and marketed (provided that proper conservation is achieved) under the natural economic laws of supply and demand. Any artificial barrier to this policy would not appear to be in the best interests of Alberta and Canada. If the future development of our gas resources is to be encouraged, a proper framework of government policy must be followed.

(h) <u>The Necessity of Export Pipe Lines to Market the Gas Potential of the Province</u>

As a result of exploration and development work done to date, the proven gas reserves of the province are considered to be at least 20 trillion cubic feet. If these reserves are to be developed within the foreseeable future, markets outside the province are essential because of the fact that Alberta markets are just not large enough. The alternative to export pipe lines is to retard the development of gas reserves until they are needed for use within provincial boundaries. Such a policy would restrict the inflow of capital into Alberta and Canada and as a result the economy of the province and the country would be retarded significantly.

It seems inevitable that if we wish to have our gas resources developed, we must also have export of gas in sizable volumes.

(i) The Potential Reserves of the Province

The Conservation Board in its report of January 31, 1957, estimated that the potential reserves of the province are of the order of 75 trillion cubic feet. This estimate was made by applying to the existing proven reserves the ratio between the total volume of sedimentary rock known to exist and that volume thereof explored to date. Other individuals or bodies have estimated the potential recoverable reserves at figures substantially higher than the 75 trillion cubic feet suggested by the Conservation Board. Assuming that the Board's estimate is a reasonable one, it would appear that substantial quantities of gas could be exported from the province without the local supply being endangered.

How much ? would it say.

Alberta Trunk

IX

THE COMPANIES' PLAN FOR SOLVING THE PROBLEM OF FUTURE SUPPLIES

13. As a result of their assessment and consideration of the various factors outlined above, the companies have rejected as unsuitable certain methods for ensuring future supplies for consumption within the province. Essentially, the idea of buying sufficient gas today to look after the 30-year requirements has been rejected because such a plan is far too expensive and the impact it would have on present day gas rates would be drastic. Moreover, the companies have rejected the idea of asking for an arbitrary allocation of reserves on the grounds that an unnatural device of this type is not consistent with our free enterprise system and would undoubtedly be unfair to certain producers.

As an alternative, the companies feel that Alberta's future requirements can best be protected by giving provincial requirements first call on all provincial gas not already committed to export. This protection can be assured by the Government of the Province adopting the principles:

(i) that on every occasion when an export permit is being considered, the proposed exporter shall establish that in addition to any quantities the export of which is requested there is a sufficient supply to meet the requirements of the distributors for a rolling period of not less than 30 years.

(ii) that the proposed exporter shall establish that such gas is available to the distributors at prices not in excess of that paid by the exporters and just as economically accessible to the distributors as the gas the export of which is in question.

(iii) that pipe line systems used for the export of gas should be available for the transport of gas to the provincial distributors on terms not more onerous than the terms on which the export gas is carried.

Assuming that gas in sufficient quantities is available for export, an agreement, which in effect embodies the foregoing, has already been entered into between these companies and Alberta and Southern Gas Co. Ltd.

This plan has many advantages:

(i) It permits the present development of the gas resources of the province.

(ii) It allows producers to seek market outlets.

(iii) It avoids the necessity for the expenditure by Alberta utility companies of the many millions of dollars that would be necessary in order to buy sufficient gas in the ground to look after the 30-year requirements of the province from time to time.

(iv) By combining gas for local use with that being delivered to export pipe lines, the economies inherent in large scale production and transmission are possible. They could not be realized if the quantities produced were restricted to those necessary to meet local market requirements only. (See Tab S for unit gas transmission costs)

In order to further this plan, Canadian Western and Northwestern have, as already pointed out, entered into a contract with a proposed gas export company (Alberta and Southern Gas Co. Ltd.) under which the requirements of the companies' customers are given priority over those of the export market. A copy of this contract is attached under Tab T.

It is expected that the companies will be able to enter into a similar type of contract with Trans-Canada Pipe Lines Limited whereby Alberta requirements would be given priority over those of Trans-Canada's markets with respect to volumes over and above the 4.35 trillion cubic feet which Trans-Canada has already been authorized to take out of Alberta. Discussions for this purpose have been held with officials of Trans-Canada.

Westcoast Transmission Company Limited have submitted to the Oil and Gas Conservation Board a form of contract under which, according to Westcoast, Alberta consumers would have access to supplies allocated to Westcoast. The companies do not consider that this form of contract affords suitable protection for Alberta consumers and have so stated their position at hearings currently before the Oil and Gas Conservation Board. The companies have stated that if Westcoast is granted a permit to export gas from the southwest corner of the province, then such permission should be contingent on their executing with the two major Alberta utility companies, a contract which is equally as favourable to Alberta consumers as is the contract hereto under Tab T.

CONCLUSIONS

The companies' markets for natural gas are expected to triple during the next 30 years.

The annual market requirements 30 years hence are anticipated to be more than 260 billion cubic feet.

Peak demands of 1,650 million cubic feet per day, more than three times Trans-Canada's presently authorized average daily rate of withdrawal from the province must be provided for.

In an area where residents are so dependent upon natural gas for meeting their heating requirements, it is of utmost importance that adequate sources of supply are always available for their use.

The meeting of these annual and peak day requirements demands careful planning and a continuing reassessment of sources of supply and market growth.

The companies realize that decisions must be made today which will have a great impact on the future.

The companies' position at the present time is summarized as follows:

(1) In the interests of the economy and welfare of Alberta and Canada, they consider that it is important to promote and develop the energy resources of the province.

(2) They are not opposed to gas export, providing that local consumers are fully protected.

(3) There must always be in sight a 30-year supply of proven reserves for the residents of the province.

In conclusion, I would like to state that it has been, and will continue to be, the policy of the companies to work with all Government agencies, boards and commissions, as well as representatives of the markets served and the gas producing industry, with the view to providing natural gas service to the maximum number of residents of the province at the lowest cost consistent with good service.

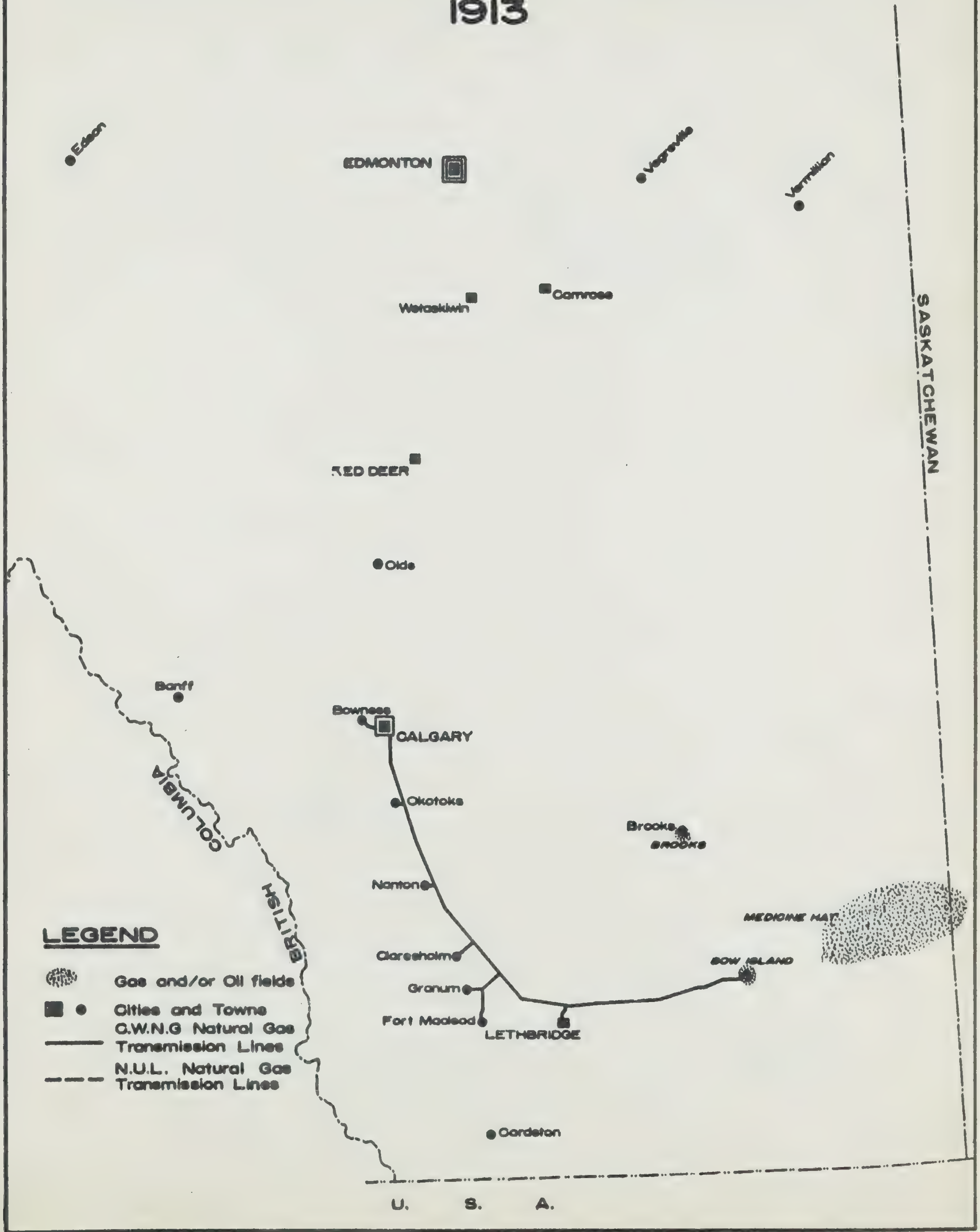
Dated at Calgary, Alberta, this 5th day of February, 1958.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

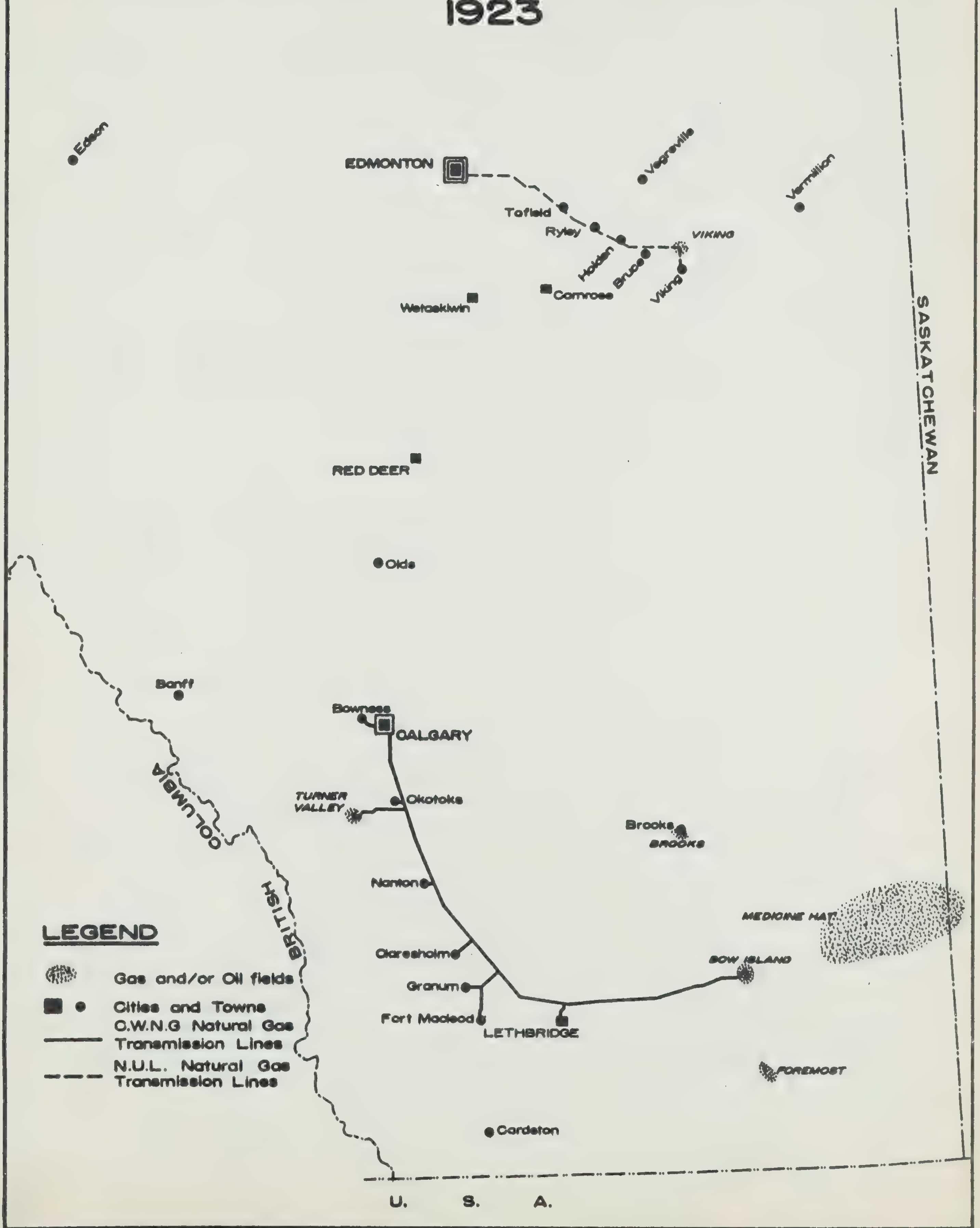
NORTHWESTERN UTILITIES, LIMITED

SYSTEMS OF NORTHWESTERN UTILITIES LTD. CANADIAN WESTERN NATURAL GAS COMPANY LTD.

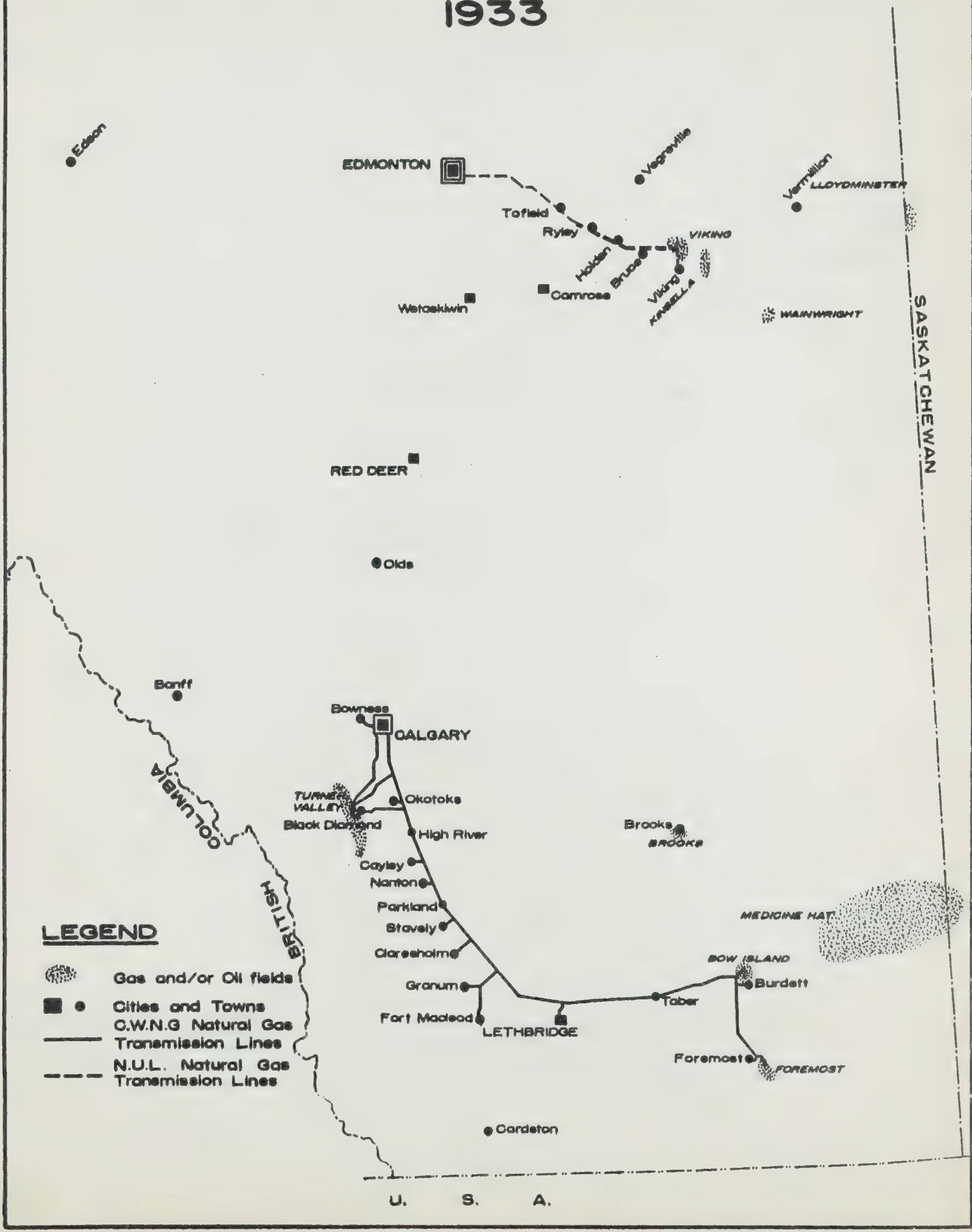
1913



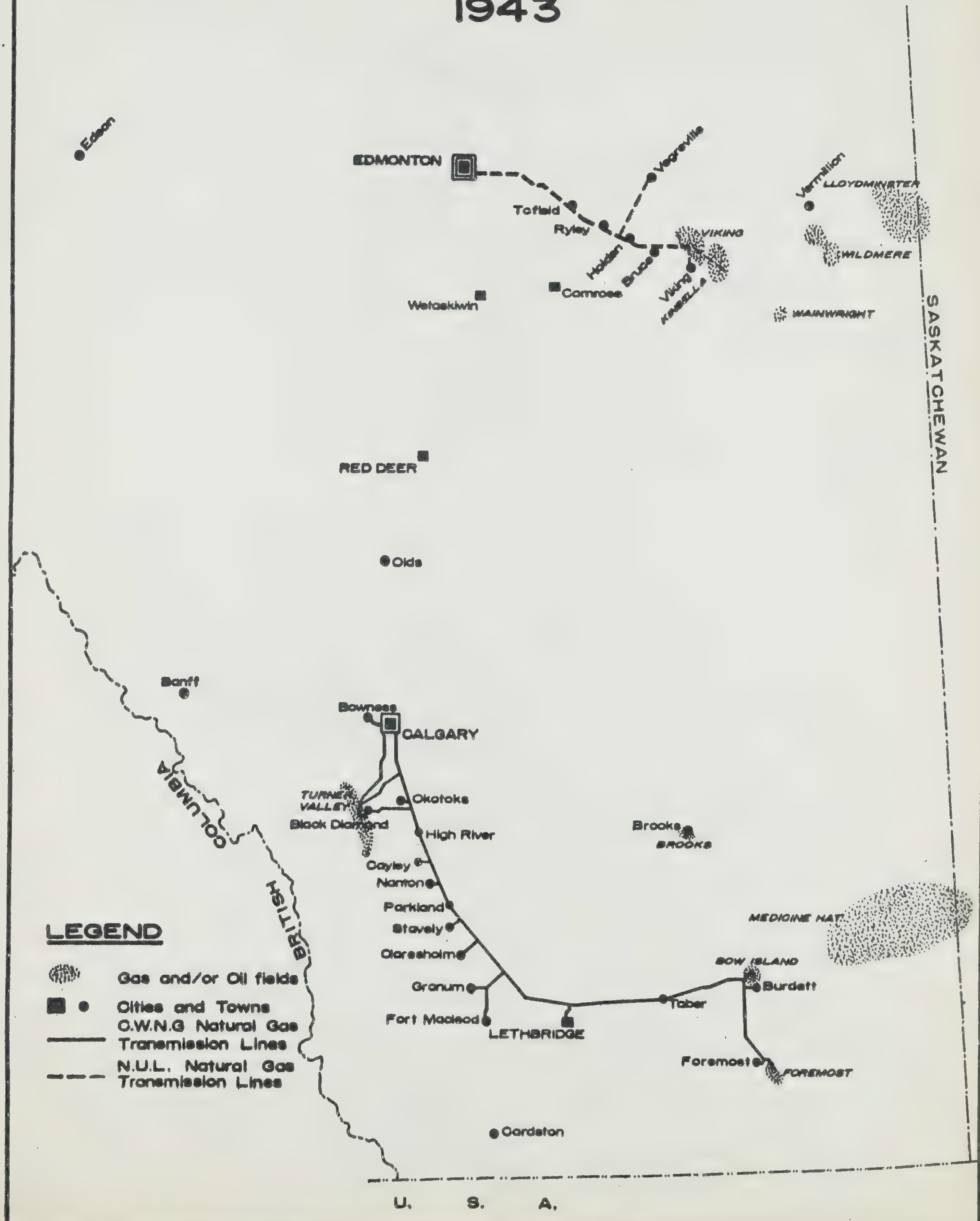
SYSTEMS OF
NORTHWESTERN UTILITIES LTD.
CANADIAN WESTERN NATURAL GAS COMPANY LTD.
1923



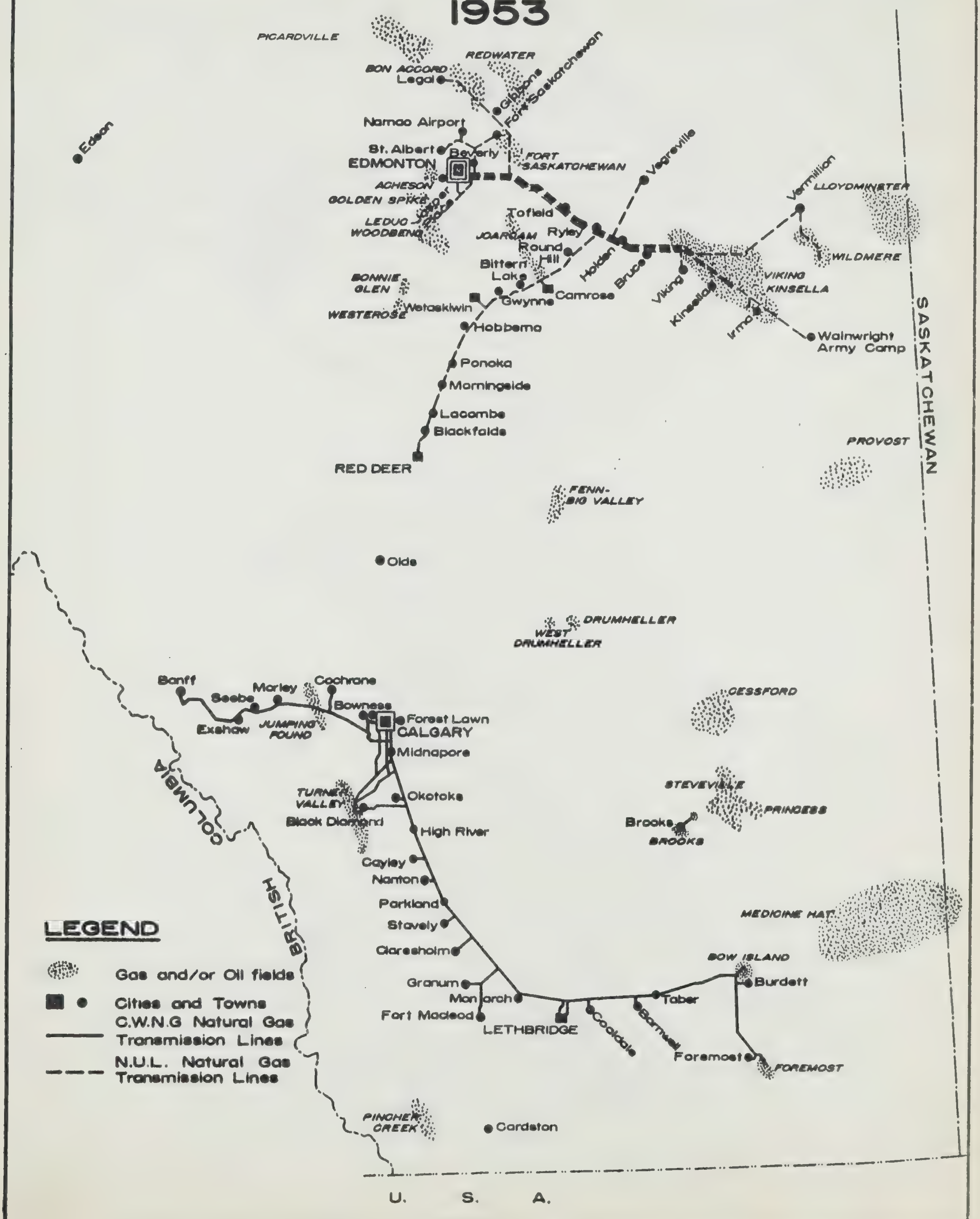
SYSTEMS OF NORTHWESTERN UTILITIES LTD. CANADIAN WESTERN NATURAL GAS COMPANY LTD. 1933



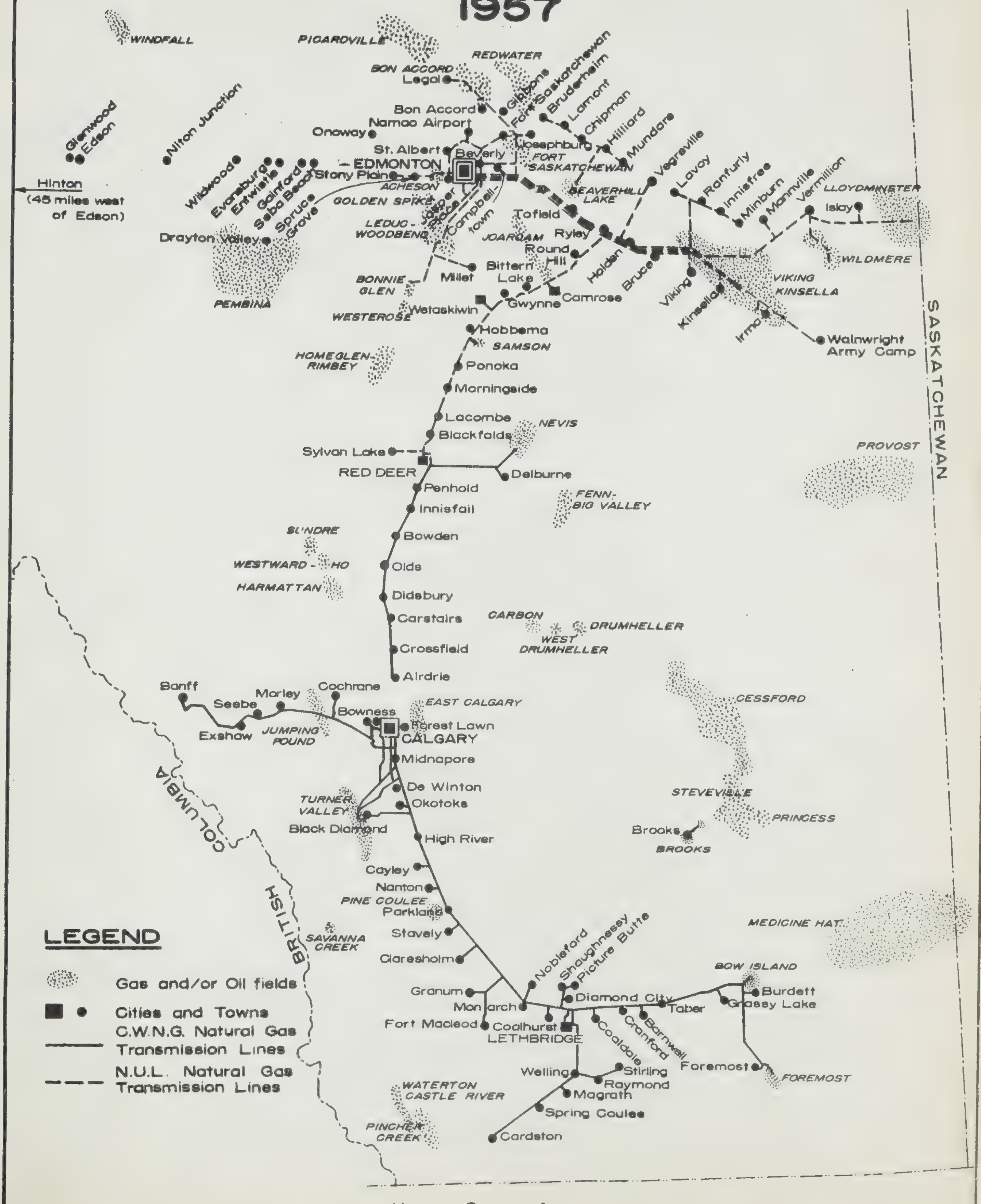
SYSTEMS OF
NORTHWESTERN UTILITIES LTD.
CANADIAN WESTERN NATURAL GAS COMPANY LTD.
1943



SYSTEMS OF
NORTHWESTERN UTILITIES LTD.
CANADIAN WESTERN NATURAL GAS COMPANY LTD.
1953



SYSTEMS OF NORTHWESTERN UTILITIES LTD. CANADIAN WESTERN NATURAL GAS COMPANY LTD. 1957

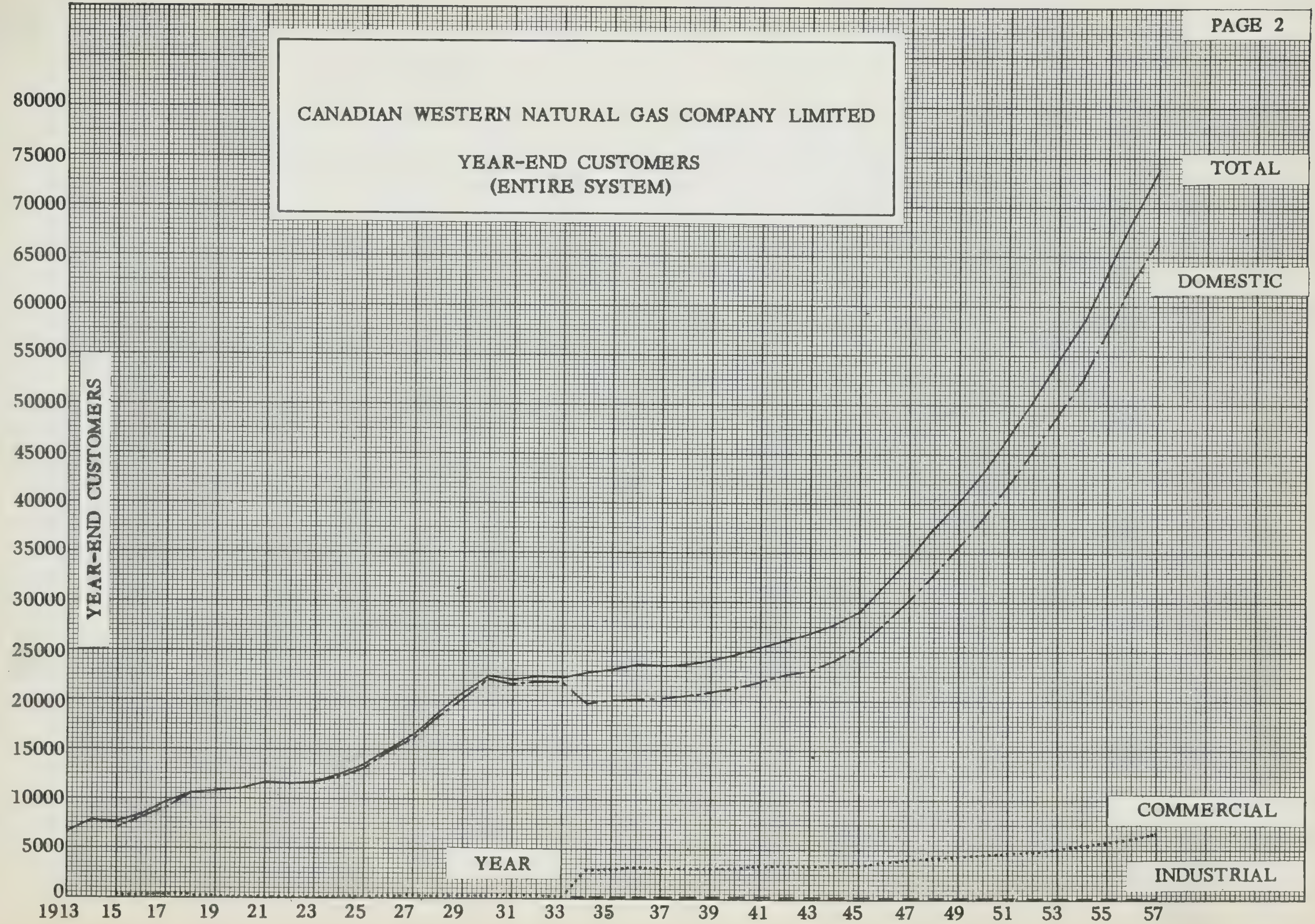


Legend
GAS and/or OIL FIELDS
CITIES and TOWNS
EXISTING NATURAL GAS TRANSMISSION LINES
PROPOSED NATURAL GAS TRANSMISSION LINES
SCALE
SYSTEM OF NORTHWESTERN UTILITIES, LIMITED
SYSTEM OF CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
Existing & Proposed Alberta Gas Trunk Line
Proposed Alberta — Southern Gas Transmission Line
Proposed Westcoast System
Pipeline owned by others
Trans-Canada Pipe Line
SASKATCHEWAN
BRITISH COLUMBIA
MONTANA
U. S. A.
OIL SANDS
McMURRAY
PEACE RIVER
WHITELAW
DUNVEGAN
POUCE COUPE
TANGENT
BELLOY
RYCROFT
STURGEON LAKE
WINDFALL
PICARDVILLE
REDWATER
FAIRYDELL
BON ACCORD
ALEXANDER
MORINVILLE
Namao Air Port
St. Albert
EDMONTON
ACHESON
GOLDEN SPIKE
LEDUC
WOODBEND
WIZARD LAKE
BONNIE GLEN
FORT SASKATCHEWAN
BEAVERHILL LAKE
JOARCAM
Camrose
Drayton Valley
PEMBINA
MINNEHIK
WESTEROSE
Hobbema
SAMSON
HOMEGLEN RIMBEY
Ponoka
Blackfalds
JOFFRE
RED DEER
NEVIS
ERSKINE
STETTLER
FENN-BIG VALLEY
Rocky Mt House
Edson
Hinton
Glenwood
Nitro Junction
JASPER NATIONAL PARK
BANFF NATIONAL PARK
SUNDRE
WESTWARD HO
HARMATTAN-ELKTON
OLDS
CARBON
WEST DRUMHELLER
DRUMHELLER
Airdrie
CALGARY
Cochrane
JUMPING POUND
SARCEE
OKOTOKS
TURNER VALLEY
Black Diamond
MAZEPPA
High River
SAVANNA CREEK
PINCHER CREEK
Granum
Lethbridge
Coaldale
Taber
Diamond City
Raymond
Magrath
Stirling
Spring Coulee
Cardston
Welling
BOW ISLAND
Burdett
Foremost
FOREMOST
ETZIKOM
PENDANT D'OREILLE
SMITH COULEE
BLACK BUTTE
COMREY
MANYBERRIES
MEDICINE HAT
SUFFIELD
PRINCESS
BROOKS
DUCHESS
STEVEVILLE
COUNTESS
CESSFORD
SUNNYNOOK
ATLEE BUFFALO
BINDLOSS
SIBBALD
OYEN
PROVOST
KESSLER
Wainwright Army Camp
VIKING - KINSELLA
WILDMERE
LLOYDMINSTER
Vegreville
Mundare
Hillard
Chipman
Holden
Bruce
Viking
Kinsella

YEAR END CUSTOMERS
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial	Total
1913	Breakdown Not Available			6,790
14				7,926
15	7,265	305	73	7,643
16	8,060	308	76	8,444
17	9,138	383	84	9,605
18	10,220	409	68	10,697
19	10,805	80	53	10,938
20	11,067	46	56	11,169
21	11,611	36	45	11,692
22	11,517	51	53	11,621
23	11,657	43	52	11,752
24	12,369	99	51	12,519
25	13,454	68	26	13,548
26	14,875	141	29	15,045
27	16,310	307	35	16,652
28	18,383	314	40	18,737
29	20,298	430	43	20,771
30	22,041	406	51	22,498
31	21,694	443	53	22,190
32	21,975	446	45	22,466
33	21,822	376	38	22,236
34	19,761	2,996	132	22,889
35	20,022	3,084	122	23,228

Year	Domestic	Commercial	Industrial	Total
1936	20,213	3,217	126	23,556
37	20,320	3,086	141	23,547
38	20,519	3,134	139	23,792
39	20,980	3,215	133	24,328
40	21,392	3,261	127	24,780
41	22,002	3,326	131	25,459
42	22,753	3,360	135	26,248
43	23,429	3,373	124	26,926
44	24,288	3,456	129	27,873
45	25,600	3,489	138	29,227
46	27,921	3,734	149	31,804
47	30,266	4,114	152	34,532
48	33,071	4,352	158	37,581
49	35,620	4,417	165	40,202
50	38,574	4,607	143	43,324
51	41,964	4,803	136	46,903
52	45,495	4,986	141	50,622
53	49,295	5,245	150	54,690
54	52,761	5,517	166	58,444
55	57,706	5,921	160	63,787
56	62,585	6,215	167	68,967
57	66,861	6,595	168	73,624


CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
YEAR-END CUSTOMERS
(ENTIRE SYSTEM)
TOTAL
DOMESTIC
COMMERCIAL
INDUSTRIAL
YEAR-END CUSTOMERS
YEAR
80000
75000
70000
65000
60000
55000
50000
45000
40000
35000
30000
25000
20000
15000
10000
5000
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1913
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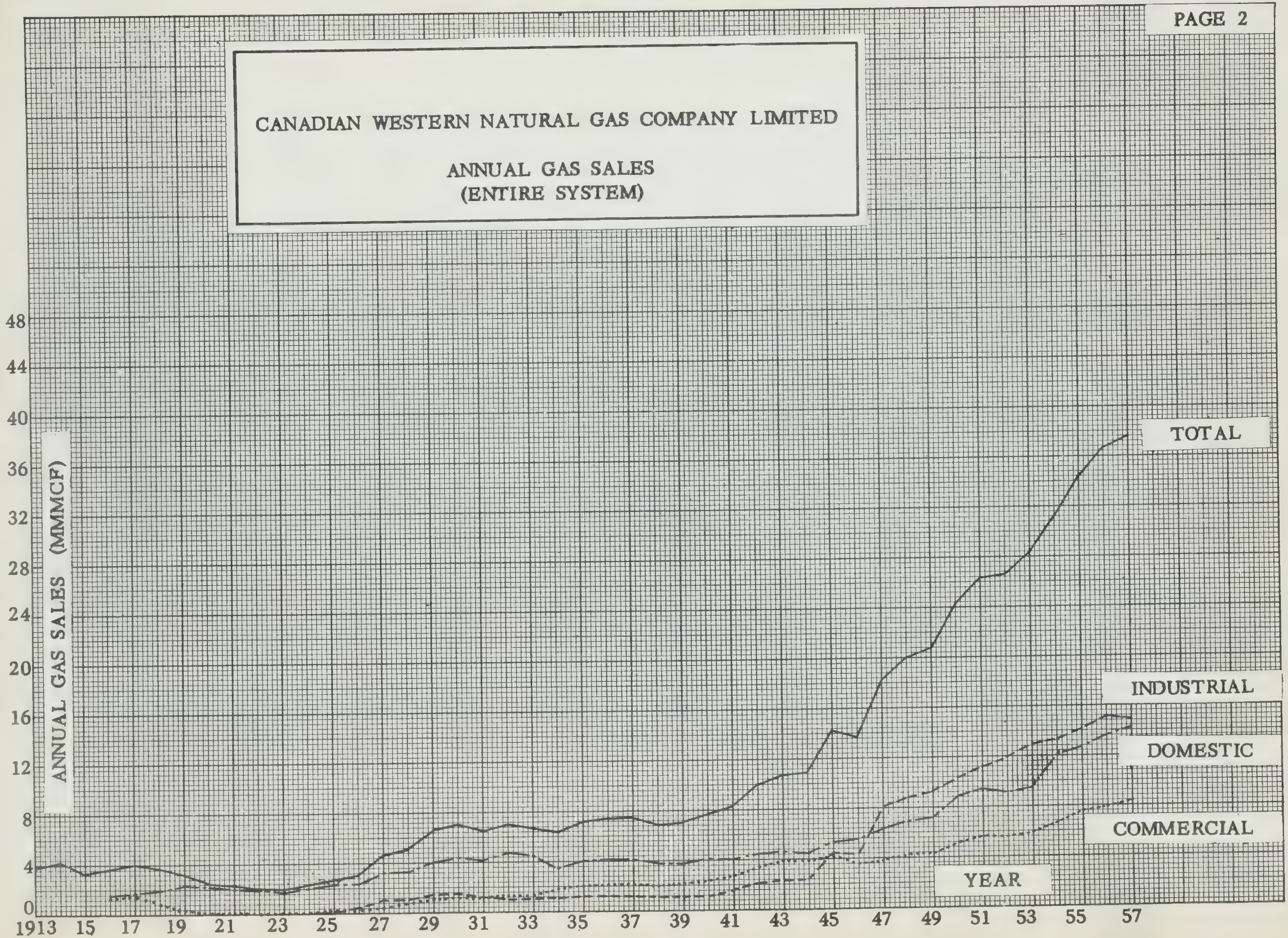
57

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

ANNUAL GAS SALES (MCF)
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial	Total
1913	Breakdown Not Available			3,729,360
14				4,186,259
15				3,263,970
16	1,514,422	756,723	1,374,442	3,645,587
17	1,729,968	805,287	1,467,051	4,002,306
18	1,928,452	870,410	930,088	3,728,950
19	2,330,983	571,960	312,430	3,214,673
20	2,229,196	202,294	88,610	2,520,100
21	1,962,634	116,961	86,658	2,166,653
22	1,861,467	110,134	75,351	2,046,952
23	1,730,789	100,462	84,432	1,915,683
24	2,086,408	139,983	125,043	2,315,434
25	2,270,336	183,689	140,974	2,594,999
26	2,290,920	227,788	468,022	2,986,730
27	3,156,754	536,519	975,623	4,668,896
28	3,294,335	778,131	1,030,309	5,102,775
29	4,085,744	1,140,453	1,387,382	6,613,579
30	4,355,906	1,249,306	1,361,566	6,966,778
31	4,122,601	1,153,908	1,218,408	6,494,917
32	4,655,897	1,329,487	1,044,447	7,029,831
33	4,453,925	1,287,660	953,270	6,694,855
34	3,421,004	1,777,795	1,095,241	6,294,040
35	4,015,344	2,042,028	1,175,899	7,233,271
1936	4,078,326	2,092,888	1,200,040	7,371,254
37	4,130,313	2,112,420	1,217,614	7,460,347
38	3,800,030	1,981,543	1,124,271	6,905,844
39	3,794,785	2,103,266	1,068,747	6,966,798
40	4,092,661	2,370,345	1,249,113	7,712,119
41	3,972,790	2,709,650	1,606,700	8,289,140
42	4,456,561	3,387,908	2,137,270	9,981,739
43	4,647,684	3,865,314	2,315,388	10,828,386
44	4,541,454	3,921,304	2,436,323	10,899,081
45	5,562,035	4,186,044	4,457,520	14,205,599
46	5,661,680	3,646,596	4,345,928	13,654,204
47	6,271,855	3,793,191	8,117,942	18,182,988
48	6,940,802	4,205,750	8,843,275	19,989,827
49	7,238,145	4,348,907	9,235,148	20,822,200
50	8,915,435	5,241,736	10,155,039	24,312,210
51	9,447,142	5,693,206	11,208,989	26,349,337
52	9,152,661	5,609,851	11,870,042	26,632,554
53	9,543,029	5,856,333	12,913,938	28,313,300
54	11,110,149	6,654,474	13,312,901	31,077,524
55	12,742,089	7,565,496	14,127,967	34,435,552
56	13,563,009	7,892,663	15,137,797	36,593,469
57	14,242,085	8,446,754	14,912,603	37,601,442

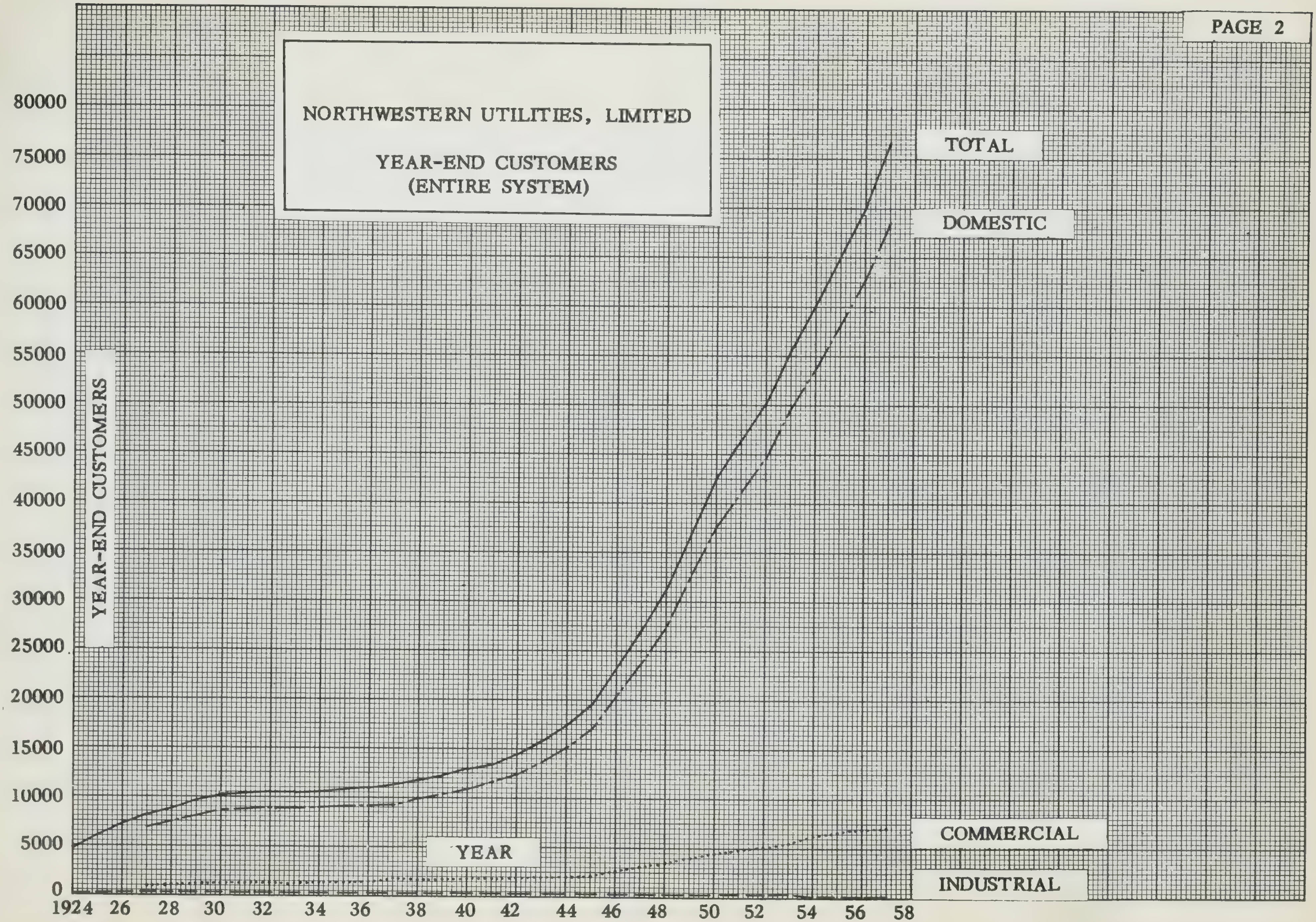

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
ANNUAL GAS SALES
(ENTIRE SYSTEM)
ANNUAL GAS SALES (MMMCF)
48
44
40
36
32
28
24
20
16
12
8
4
0
1913
15
17
19
21
23
25
27
29
31
33
35
37
39
41
43
45
47
49
51
53
55
57
YEAR
TOTAL
INDUSTRIAL
DOMESTIC
COMMERCIAL

NORTHWESTERN UTILITIES, LIMITED

YEAR END CUSTOMERS
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial	Total
1924	4,808		67	4,875
25	5,998		249	6,247
26	7,026		247	7,273
27	6,868	969	258	8,095
28	7,526	1,112	310	8,948
29	8,110	1,261	327	9,698
30	8,605	1,325	329	10,259
31	8,786	1,360	318	10,464
32	8,835	1,374	312	10,521
33	8,806	1,363	309	10,478
34	8,949	1,412	312	10,673
35	9,114	1,420	353	10,887
36	9,291	1,488	353	11,132
37	9,391	1,717	351	11,459
38	9,955	1,643	339	11,937
39	10,376	1,705	338	12,419
40	10,865	1,790	328	12,983
1941	11,660	1,846	310	13,816
42	12,429	1,905	313	14,647
43	13,620	2,038	316	15,974
44	15,082	2,125	310	17,517
45	17,025	2,215	316	19,556
46	20,367	2,688	321	23,376
47	23,792	3,129	363	27,284
48	27,392	3,522	428	31,342
49	32,598	4,041	449	37,088
50	37,673	4,514	462	42,649
51	41,153	4,854	476	46,483
52	44,689	5,095	477	50,261
53	49,646	5,543	509	55,698
54	53,750	6,355	249	60,354
55	58,158	6,748	249	65,155
56	62,785	6,998	225	70,008
57	68,694	7,605	221	76,520

NOTE: Domestic and Commercial customers were not separated 1924 - 1926


NORTHWESTERN UTILITIES, LIMITED
YEAR-END CUSTOMERS
(ENTIRE SYSTEM)
TOTAL
DOMESTIC
COMMERCIAL
INDUSTRIAL
YEAR-END CUSTOMERS
YEAR
80000
75000
70000
65000
60000
55000
50000
45000
40000
35000
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NORTHWESTERN UTILITIES, LIMITED

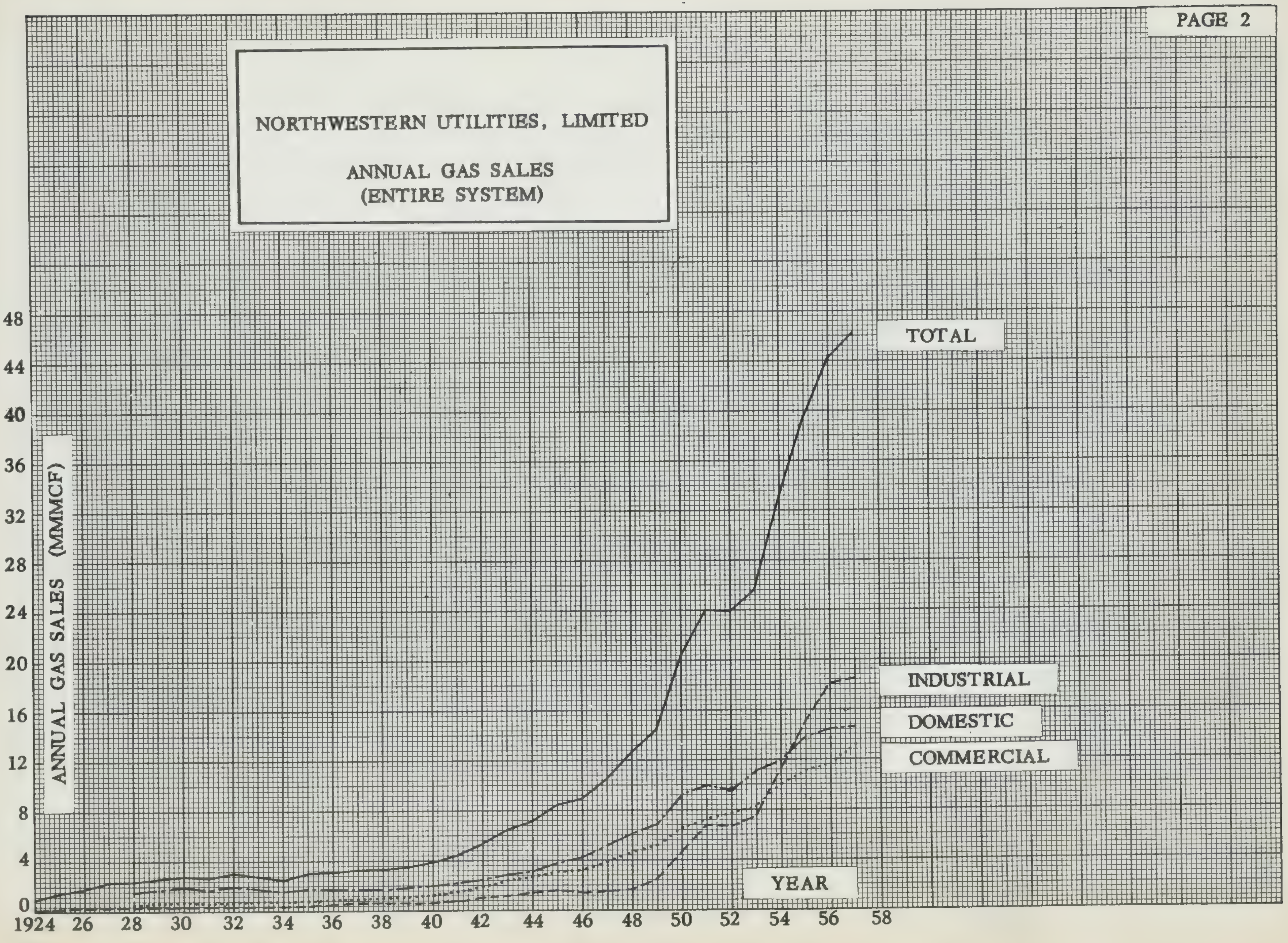
ANNUAL GAS SALES (MCF)
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial	Total
1924	830,676		117,847	948,523
25	1,333,207		215,758	1,548,965
26	1,510,134		263,819	1,773,953
27	2,013,063		304,339	2,317,402
28	1,542,670	505,838	322,605	2,371,113
29	1,702,875	579,211	337,623	2,619,709
30	1,823,741	651,630	334,786	2,810,157
31	1,700,272	628,443	315,269	2,643,984
32	1,910,423	716,595	332,898	2,959,916
33	1,738,517	709,858	297,171	2,745,546
34	1,535,974	658,843	281,652	2,476,469
35	1,732,703	839,148	443,816	3,015,667
36	1,737,978	909,396	481,697	3,129,071
37	1,744,839	939,028	600,345	3,284,212
38	1,706,059	1,028,910	595,315	3,330,284
39	1,842,486	1,104,349	565,504	3,512,339
40	1,967,680	1,331,857	623,446	3,939,712 *

Year	Domestic	Commercial	Industrial	Total
1941	2,159,707	1,489,520	748,048	4,424,112 *
42	2,472,168	1,867,810	953,105	5,293,083
43	2,877,426	2,371,543	1,242,012	6,490,981
44	3,062,446	2,692,387	1,387,984	7,142,817
45	3,807,562	3,091,697	1,610,108	8,509,367
46	4,222,458	3,238,497	1,415,877	8,876,832
47	5,173,673	3,885,209	1,457,411	10,516,293
48	6,113,966	4,726,653	1,744,164	12,584,813
49	6,829,272	5,175,579	2,494,853	14,499,704
50	9,201,887	6,589,298	4,729,739	20,520,924
51	9,948,651	7,264,669	6,789,163	24,002,483
52	9,599,494	7,652,844	6,663,876	23,916,214
53	10,091,441	8,245,053	7,375,075	25,711,569
54	11,907,399	9,993,532	11,255,177	33,156,108
55	13,757,675	11,144,887	15,091,674	39,594,236
56	14,440,964	11,735,032	18,109,566	44,285,562
57	14,554,013	13,168,670	18,503,728	46,266,411

* NOTE: Gas Sales to Vegreville Gas Company included in total only - 1940 - 16,729 MCF
1941 - 26,837 MCF

NOTE: Domestic and Commercial Gas Sales were not separated 1924 - 1927


NORTHWESTERN UTILITIES, LIMITED
ANNUAL GAS SALES
(ENTIRE SYSTEM)
ANNUAL GAS SALES (MMMCF)
48
44
40
36
32
28
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16
12
8
4
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1924
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48
50
52
54
56
58
YEAR
TOTAL
INDUSTRIAL
DOMESTIC
COMMERCIAL

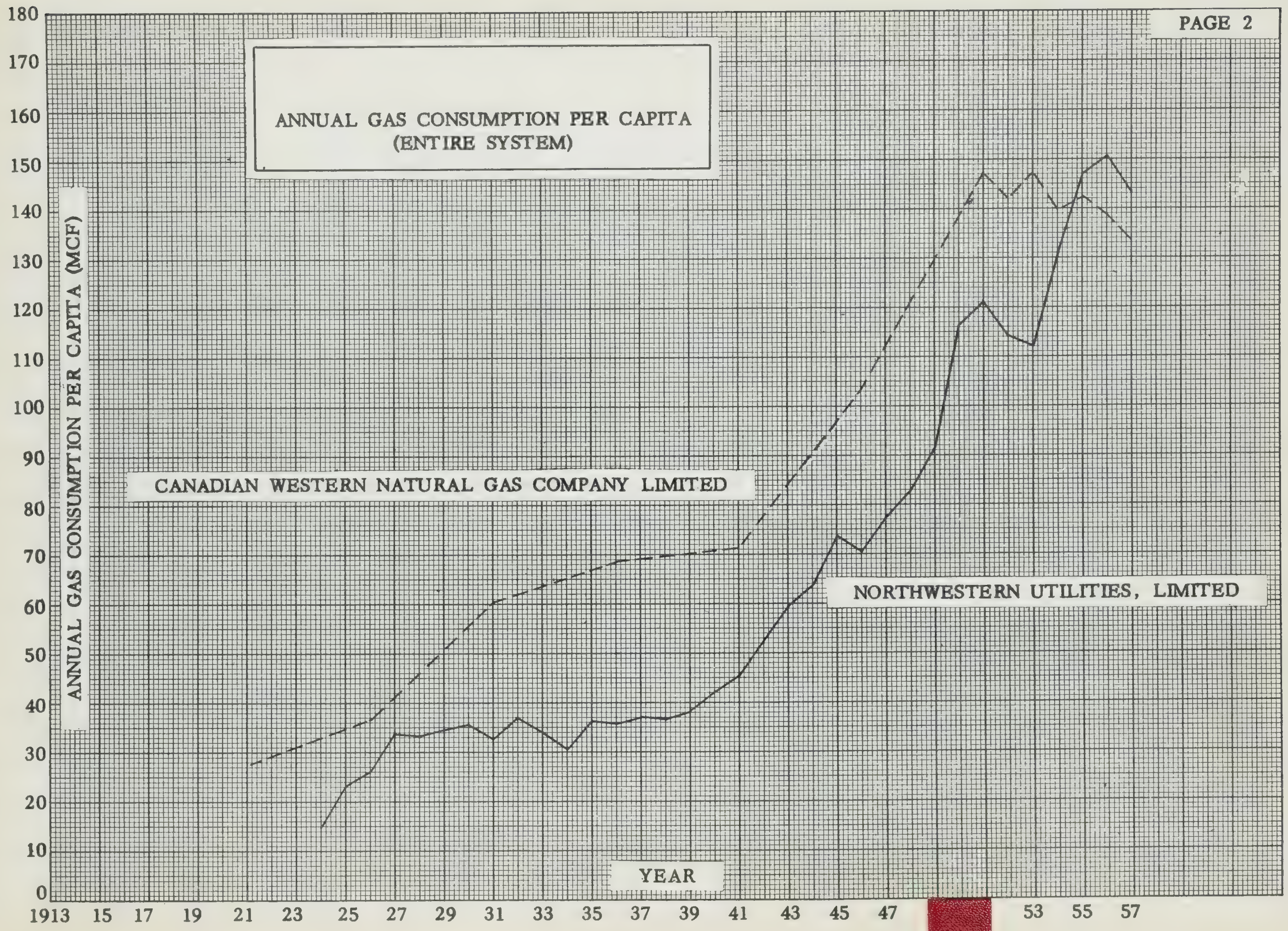
NORTHWESTERN UTILITIES, LIMITED
and
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

ANNUAL GAS CONSUMPTION PER CAPITA (MCF)
(ENTIRE SYSTEM)

Year	Northwestern Utilities, Limited	Canadian Western Natural Gas Company Limited
1913		
14		
15		
16		
17		
18		
19		
20		
21		27.3
22		
23		
24	14.7	
25	23.2	
26	26.1	36.7
27	33.8	
28	33.3	
29	34.6	
30	35.5	
31	32.8	60.3
32	37.0	
33	34.0	
34	30.4	
35	36.2	

Year	Northwestern Utilities, Limited	Canadian Western Natural Gas Company Limited
1936	35.9	68.9
37	37.0	
38	36.8	
39	38.1	
40	42.1	
41	45.4	71.2
42	52.8	
43	59.5	
44	63.8	
45	73.8	
46	70.5	103.3
47	77.5	
48	82.8	
49	91.8	
50	116.6	
51	121.3	147.2
52	114.1	142.0
53	112.1	147.1
54	131.1	139.8
55	147.0	142.3
56	150.5	139.0
57	143.5	133.7

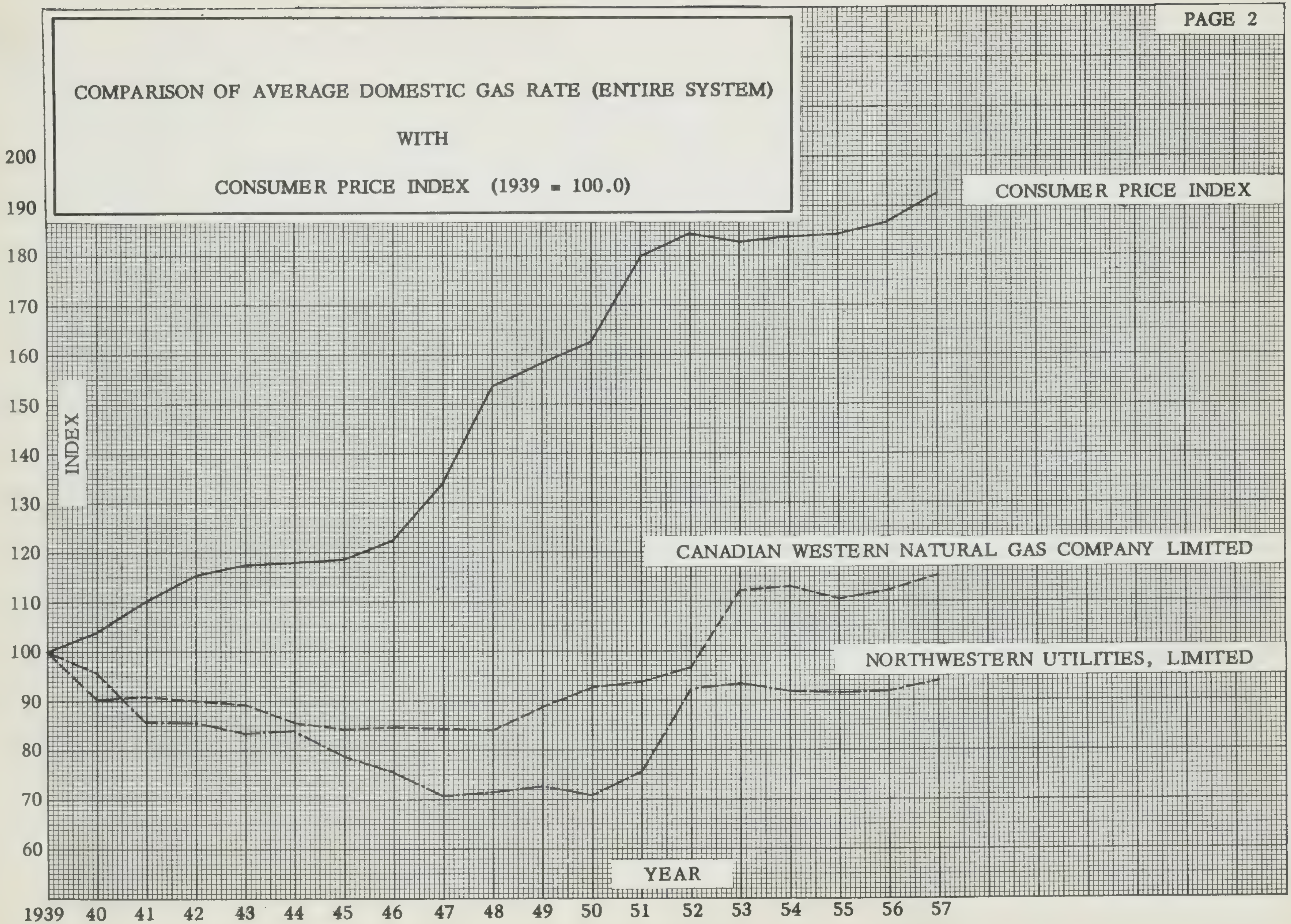
NOTE: Canadian Western Natural Gas Company Limited - Accurate population data not available prior to 1951 except on Dominion Census years.


ANNUAL GAS CONSUMPTION PER CAPITA
(ENTIRE SYSTEM)
ANNUAL GAS CONSUMPTION PER CAPITA (MCF)
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
NORTHWESTERN UTILITIES, LIMITED
YEAR
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1913
15
17
19
21
23
25
27
29
31
33
35
37
39
41
43
45
47
53
55
57

NORTHWESTERN UTILITIES, LIMITED
and
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

COMPARISON OF AVERAGE DOMESTIC GAS RATE
(ENTIRE SYSTEM) WITH CONSUMER PRICE INDEX

Year	Northwestern Utilities, Limited - Average Domestic Gas Rate	Canadian Western Natural Gas Company Limited - Average Domestic Gas Rate	Consumer Price Index (1939 - 100.0)
1939	100.0	100.0	100.0
40	95.6	90.3	104.0
41	85.5	90.7	110.1
42	84.4	90.0	115.3
43	83.4	89.1	117.4
44	83.9	85.4	118.0
45	78.7	84.2	118.7
46	75.3	84.4	122.6
47	70.6	84.1	134.2
48	71.4	84.0	153.5
49	72.7	88.8	158.2
50	70.9	92.5	162.8
51	75.6	93.7	179.9
52	92.2	96.8	184.3
53	93.2	112.2	182.8
54	91.9	113.0	183.9
55	91.7	110.4	184.2
56	91.9	112.2	186.9
57	94.0	115.2	192.9

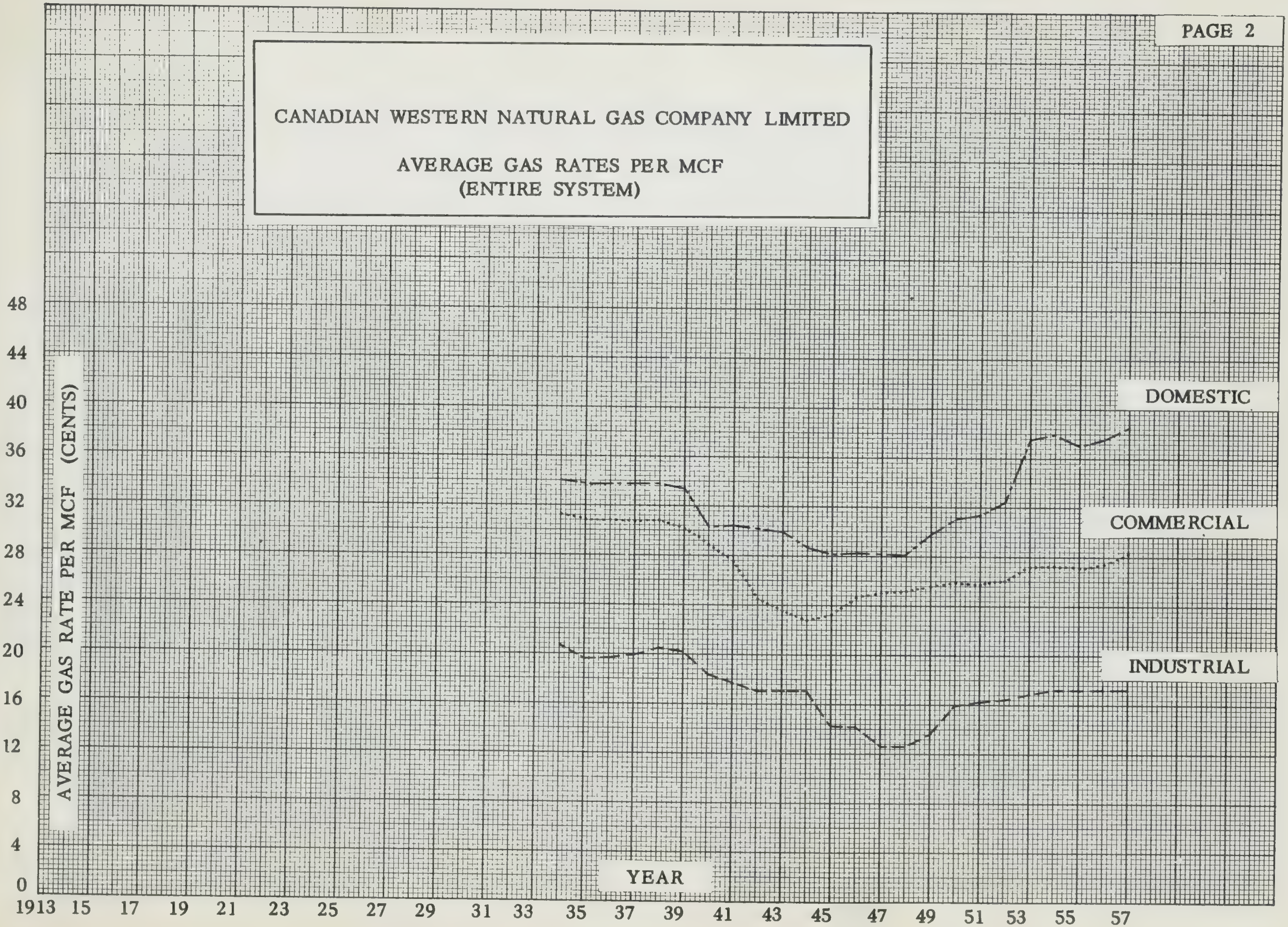

COMPARISON OF AVERAGE DOMESTIC GAS RATE (ENTIRE SYSTEM)
WITH
CONSUMER PRICE INDEX (1939 = 100.0)
CONSUMER PRICE INDEX
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
NORTHWESTERN UTILITIES, LIMITED
INDEX
200
190
180
170
160
150
140
130
120
110
100
90
80
70
60
YEAR
1939
40
41
42
43
44
45
46
47
48
49
50
51
52
53
54
55
56
57

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

AVERAGE GAS RATE PER MCF (CENTS)
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial
1913			
14			
15			
16		BREAKDOWN	
17			
18			
19		NOT	
20			
21		AVAILABLE	
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34	34.0	31.2	20.7
35	33.8	30.9	19.6

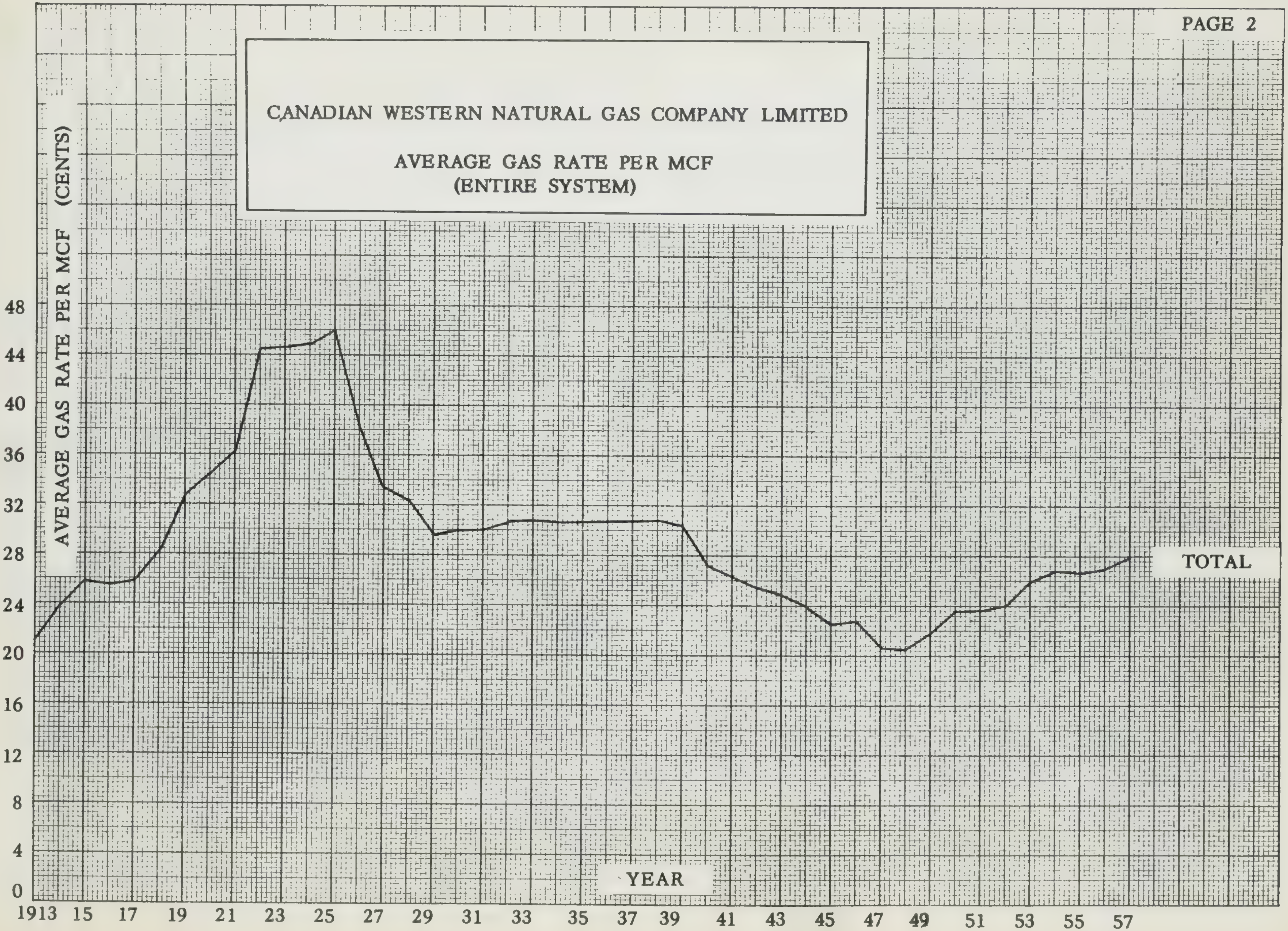
Year	Domestic	Commercial	Industrial
1936	33.8	30.8	19.6
37	33.8	30.7	19.9
38	33.8	30.8	20.5
39	33.5	30.2	20.2
40	30.3	26.9	18.4
41	30.4	25.6	17.7
42	30.2	24.5	17.0
43	29.9	23.5	17.1
44	28.7	22.7	17.1
45	28.2	23.2	14.2
46	28.3	24.6	14.2
47	28.2	25.0	12.6
48	28.2	25.1	12.6
49	29.8	25.5	13.7
50	31.0	25.8	15.9
51	31.4	25.7	16.2
52	32.5	26.0	16.5
53	37.6	27.2	16.9
54	37.9	27.3	17.2
55	37.0	27.1	17.2
56	37.6	27.4	17.2
57	38.6	28.2	17.3


CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
AVERAGE GAS RATES PER MCF
(ENTIRE SYSTEM)
DOMESTIC
COMMERCIAL
INDUSTRIAL
AVERAGE GAS RATE PER MCF (CENTS)
48
44
40
36
32
28
24
20
16
12
8
4
0
YEAR
1913 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51 53 55 57

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

AVERAGE GAS RATE PER MCF (CENTS)
(ENTIRE SYSTEM)

Year	Total Average Rate Per MCF	Year	Total Average Rate Per MCF
		1936	30.7
		37	30.7
1913	21.0	38	30.8
14	23.8	39	30.5
15	25.8	40	27.3
16	25.6	41	26.4
17	25.9	42	25.4
18	28.3	43	24.9
19	32.8	44	23.9
20	34.4	45	22.5
21	36.2	46	22.8
22	44.5	47	20.6
23	44.6	48	20.6
24	44.9	49	21.8
25	46.0	50	23.6
26	38.4	51	23.7
27	33.5	52	24.0
28	32.4	53	26.0
29	29.6	54	26.8
30	29.9	55	26.7
31	30.1	56	27.0
32	30.6	57	27.9
33	30.7		
34	30.6		
35	30.7		

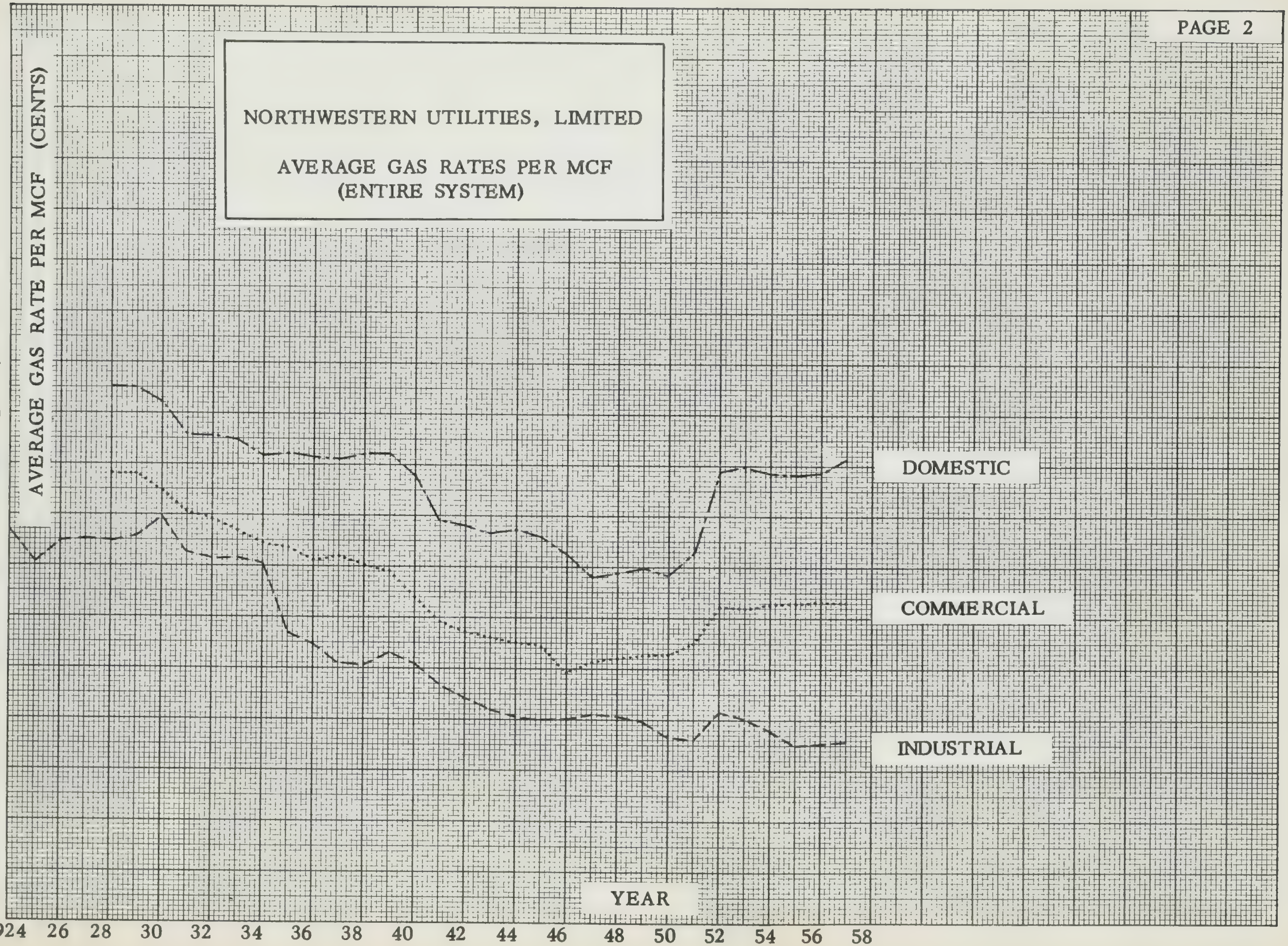

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
AVERAGE GAS RATE PER MCF
(ENTIRE SYSTEM)
AVERAGE GAS RATE PER MCF (CENTS)
0
4
8
12
16
20
24
28
32
36
40
44
48
YEAR
1913
15
17
19
21
23
25
27
29
31
33
35
37
39
41
43
45
47
49
51
53
55
57
TOTAL

NORTHWESTERN UTILITIES, LIMITED

AVERAGE GAS RATES PER MCF (CENTS)
(ENTIRE SYSTEM)

Year	Domestic	Commercial	Industrial
1924	Breakdown Not Available		30.8
25			28.3
26			29.9
27			30.1
28	42.1	35.3	29.9
29	42.0	35.2	30.3
30	40.9	33.9	31.9
31	38.3	32.2	29.1
32	38.3	31.7	28.6
33	37.9	30.8	28.7
34	36.7	29.8	28.2
35	36.9	29.4	22.8
36	36.6	28.5	21.9
37	36.5	28.8	20.4
38	36.9	28.1	20.3
39	36.9	27.7	21.3
40	35.2	25.6	20.4

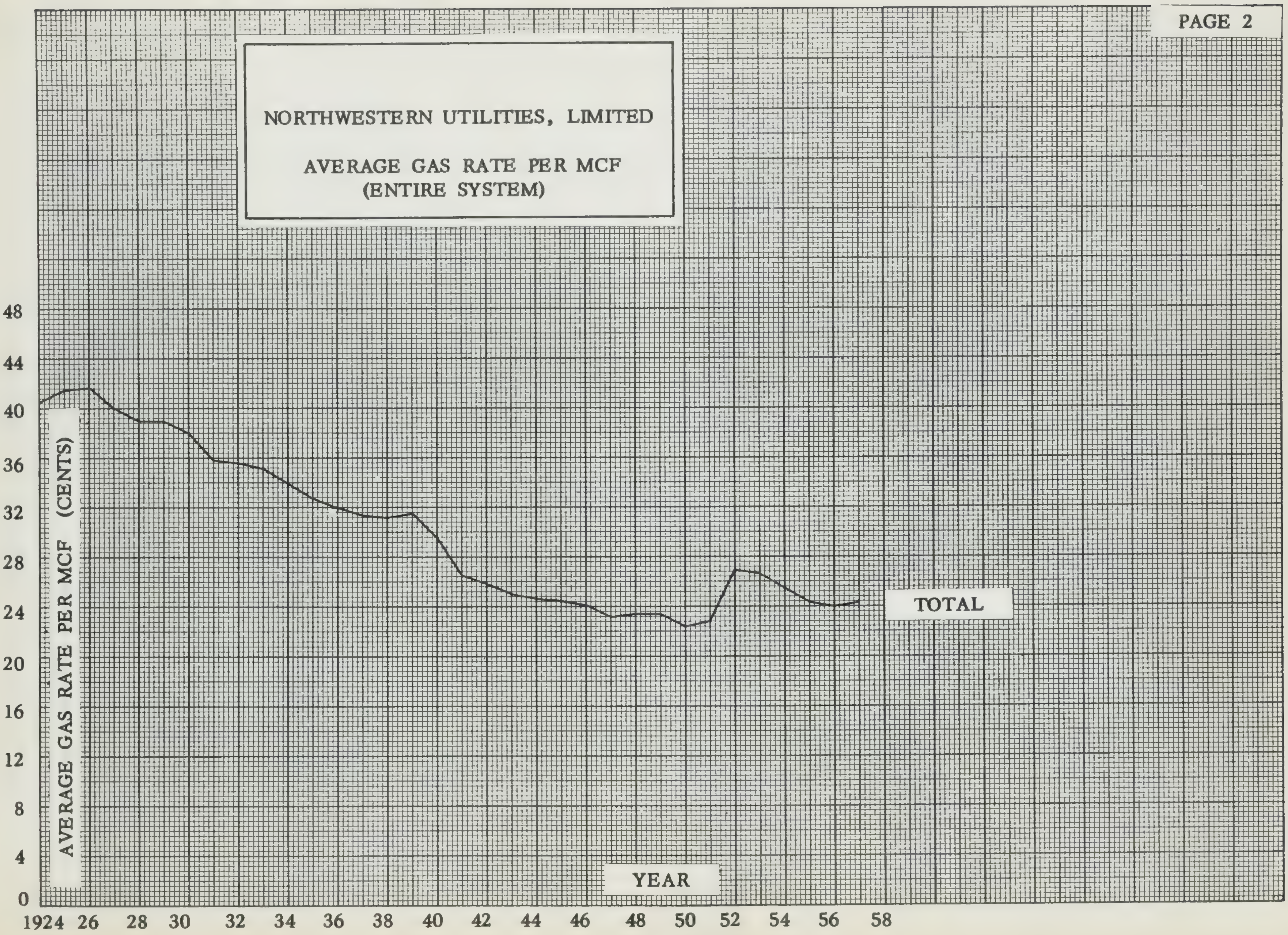
Year	Domestic	Commercial	Industrial
1941	31.6	23.7	18.7
42	31.2	22.9	17.7
43	30.7	22.4	16.8
44	30.9	22.0	16.2
45	30.3	21.8	16.0
46	29.0	19.7	16.0
47	27.2	20.5	16.4
48	27.5	20.8	16.2
49	28.0	21.0	15.9
50	27.3	21.1	14.6
51	29.1	22.0	14.5
52	35.5	24.9	16.6
53	35.9	24.8	16.1
54	35.4	25.0	15.2
55	35.3	25.1	14.0
56	35.4	25.3	14.2
57	36.6	25.2	14.3


NORTHWESTERN UTILITIES, LIMITED
AVERAGE GAS RATES PER MCF
(ENTIRE SYSTEM)
AVERAGE GAS RATE PER MCF (CENTS)
48
44
40
36
32
28
24
20
16
12
8
4
0
1924
26
28
30
32
34
36
38
40
42
44
46
48
50
52
54
56
58
YEAR
DOMESTIC
COMMERCIAL
INDUSTRIAL

NORTHWESTERN UTILITIES, LIMITED

AVERAGE GAS RATE PER MCF (CENTS)
(ENTIRE SYSTEM)

Year	Total Average Rate Per MCF	Year	Total Average Rate Per MCF
		1941	26.5
		42	25.8
		43	25.0
1924	40.5	44	24.7
25	41.5	45	24.5
26	41.7	46	24.1
27	40.0	47	23.2
28	39.0	48	23.4
29	39.0	49	23.4
30	38.0	50	22.4
31	35.8	51	22.8
32	35.6	52	26.9
33	35.1	53	26.6
34	33.9	54	25.4
35	32.7	55	24.3
36	32.0	56	24.0
37	31.4	57	24.4
38	31.2		
39	31.5		
40	29.5		


NORTHWESTERN UTILITIES, LIMITED
AVERAGE GAS RATE PER MCF
(ENTIRE SYSTEM)
AVERAGE GAS RATE PER MCF (CENTS)
48
44
40
36
32
28
24
20
16
12
8
4
0
TOTAL
YEAR
1924
26
28
30
32
34
36
38
40
42
44
46
48
50
52
54
56
58

Canadian Western Natural Gas Company Limited

CALGARY ALBERTA

Schedule of Rates

CALGARY - LETHBRIDGE SYSTEM

Effective in Cities of Calgary and Lethbridge, and the Towns and Villages of Barnwell, Black Diamond, Bowness, Burdett, Cayley, Claresholm, Coaldale, Foremost, Fort Macleod, Granum, High River, Monarch, Nanton, Okotoks, Parkland, Stavely and Taber.

P.U.B. Order No. 14332 Feb. 1953

GENERAL RATE — No. 1

Availability:

Available to all customers (Domestic, Commercial and Industrial).

Net Rate:

First 2 M.C.F. or Less per month **$2.50**
All additional M.C.F. per month .... **26¢** per M.C.F.

Minimum Monthly Charge — $2.50

General Conditions:

1. When accounts are not paid on or before the due date, the charge per M.C.F. other than the first two M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply.
2. This rate shall be effective on all meter readings on or after February 28th, 1953.

OPTIONAL RATE — No. 2

Availability:

This schedule is available to all customers using in excess of 9,906 M.C.F. per year.

Net Rates:

(A) Customers whose annual consumption is greater than 9,906 M.C.F. per year and less than 34,000 per year:
FIXED CHARGE .... **$35.00** per month
plus
COMMODITY CHARGE .... **22¢** per M.C.F.

Minimum Monthly Charge — $35.00

(B) Customers whose annual consumption is greater than 34,000 M.C.F. per year:
FIXED CHARGE .... **$120.00** per month
plus
COMMODITY CHARGE .... **19¢** per M.C.F.

Minimum Monthly Charge — $120.00

General Conditions:

1. This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year, it shall cease and determine.
2. When accounts are not paid on or before the due date the charges per M.C.F. shall be increased as follows: Rate (A) 3¢, Rate (B) 2¢. The Gross Rate so arrived at shall then apply.
3. When a customer has been billed under one subsection, (A) or (B), of this rate and at the end of the year it is found that he should have been billed under another subsection, his account for that year shall be adjusted and the necessary refund made by the company.
4. This rate shall be effective on all meter readings on or after February 28, 1953.

HIGH LOAD FACTOR RATE — No. 3

Availability:

To customers on annual contract whose annual consumption of gas is not less than 12,000 M.C.F., and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption for the year.

Net Rate:

FIXED CHARGE—$20.00 per month plus
$ 1.00 per month per 1,000 cu. ft. of maximum 12-hour demand.

plus

COMMODITY CHARGE—	First 2,000 M.C.F. per month	—**19¢**	per M.C.F.
	Next 2,000 M.C.F. per month	—**16¢**	per M.C.F.
	Next 150,000 M.C.F. per month	—**14¢**	per M.C.F.
	All additional M.C.F. per month	—**13.5¢**	per M.C.F.

Minimum Monthly Charge — Fixed Charge

Determination of Demand:

The maximum twelve-hour demand shall be the greatest amount of gas in cubic feet delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods, as determined by the company by measurement. The maximum twelve-hour demand of a new consumer of gas shall be estimated by the company.

Provided that the company may, with the approval of the Board of Public Utility Commissioners, take into consideration in determining the fixed charge the effect of the consumer's demand for gas upon the company's peak load.

General Conditions:

1. This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year it shall cease and determine.

2. This rate shall be effective on all meter readings on or after February 28, 1953.

CALGARY SUBURBAN AREAS

GENERAL RATE No. 1A

Availability:

Available to all customers (Domestic, Commercial and Industrial) in a number of suburban areas adjacent to the

City of Calgary, including Forest Lawn, Cossar, Meadowfield, Lincoln Park and Midnapore.

Net Rate:

First 2 M.C.F. or Less per month **$2.50**
All additional M.C.F. per month .... **40¢** per M.C.F.

Minimum Monthly Charge — $2.50

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. other than the first two, shall be increased by 4¢ and the Gross Rate so arrived at shall apply.

OPTIONAL RATE

Effective January 1, 1955

Available to all consumers using in excess of 830 M.C.F. per year.

FIXED CHARGE .... **$10.00** per month
plus
COMMODITY CHARGE .... **28¢** per M.C.F.

Minimum Monthly Charge — $10.00

Penalty for late payment 3¢ per M.C.F.

CARDSTON, DIAMOND CITY, GRASSY LAKE, MAGRATH, NOBLEFORD, PICTURE BUTTE, RAYMOND, SHAUGHNESSY AND STIRLING

GENERAL RATE — No. 1

Effective — March 1955

Availability:

Available to all customers.

Net Rate:

First 2 M.C.F. or Less per month **$2.50**
All additional M.C.F. per month .... **65¢** per M.C.F.

Minimum Monthly Charge — $2.50

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. other than the first two M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply. shall apply.

OPTIONAL RATE — No. 2

Effective — March 1955

Availability:

This rate is available to all customers using in excess of 542 M.C.F. per year.

Net Rate:

FIXED CHARGE .... **$12.50** per month
plus
COMMODITY CHARGE .... **40¢** per M.C.F.

Minimum Monthly Charge — $12.50

General Conditions:

1. This rate is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year it shall cease and determine.
2. When accounts are not paid on or before the due date, the charge per M.C.F. shall be increased by 3¢ and the Gross Rate so arrived at shall apply.

OFF-PEAK OR INTERRUPTIBLE SERVICE RATE No. 3

Effective — June 1956

Availability:

This rate is available to customers using in excess of 5,000 M.C.F. per year, who either agree to use no gas in the five winter months of January, February, March, November and December, or who agree that their consumption in such months is subject to curtailment or interruption if the company's gas supplies and system facilities are required to maintain service to customers other than those receiving gas subject to such curtailment or interruption.

Net Rate:

FIXED CHARGE .... **$20.00** per month
plus
COMMODITY CHARGE—First 2,000 M.C.F. per month—**30¢** per M.C.F.
Next 2,000 M.C.F. per month—**27¢** per M.C.F.
All additional M.C.F. per month—**24¢** per M.C.F.

Minimum Monthly Charge — $20.00

General Conditions:

1. For service under this rate, the customer agrees to curtail or discontinue the use of gas whenever and so often as requested to do so by the company. The company, however, if circumstances permit, will endeavour to give the customer advance notice of curtailment or cut-off by telephone or otherwise.

2. Customers served under this rate must give satisfactory evidence of their ability and willingness to discontinue the use of gas during periods of curtailment or interruption by the use of standby facilities, plant shut down or otherwise.

3. Gas supplied under this rate will be separately metered and not used interchangeably with gas supplied under any other rate.

BROOKS

P.U.B. Order No. 15120, Dec. 14, 1953

GENERAL RATE — No. 1

Availability:

Available to all customers (Domestic, Commercial and Industrial).

Net Rate:

First 4 M.C.F. or Less per month	**$2.50**
All additional M.C.F. per month	**34¢** per M.C.F.
Minimum Monthly Charge	**$2.50**

General Conditions:

1. When accounts are not paid on or before the due date, the charge per M.C.F. other than the first four M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply.

2. This rate shall be effective on all bills rendered on or after January 1, 1954.

OPTIONAL RATE — No. 2

Availability:

This rate is available to all customers using in excess of 5,886 M.C.F. per year.

Net Rate:

FIXED CHARGE .... **$60.00** per month
plus
COMMODITY CHARGE .... **22¢** per M.C.F.

Minimum Monthly Charge — $60.00

General Conditions:

1. This rate is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year it shall cease and determine.

2. When accounts are not paid on or before the due date, the charge per M.C.F. shall be increased by 2¢ and the Gross Rate so arrived at shall apply.

3. This rate shall be effective on all bills rendered on or after January 1, 1954.

BANFF - EXSHAW - COCHRANE SYSTEM

Applicable in Banff, Canmore, Exshaw, Seebe, Morley and Cochrane, Effective January 1955

GENERAL RATE

Availability:

Available to all customers (Domestic, Commercial and Industrial).

Net Rate:

First 2 M.C.F. or Less per month **$2.50**
All additional M.C.F. per month .... **42¢** per M.C.F.
Minimum Monthly Charge — $2.50

Special Conditions:

Whenever a customer orders the gas to be turned on under this rate within twelve months of the date of the previous turn off, a "Turn on Charge" of $5.00 will be made.

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. other than the first two M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply.

OPTIONAL RATE "A"

Availability:

This rate is available to all customers, but only on annual contract.

Net Rate:

FIXED CHARGE .... **$1.50** per month
plus
COMMODITY CHARGE .... **50¢** per M.C.F.
Minimum Monthly Charge — $1.50

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply.

OPTIONAL RATE "B"

Availability:

This rate is available to all customers using in excess of 715 M.C.F. per year, but only on annual contract.

Net Rate:

FIXED CHARGE .... **$10.00** per month
plus
COMMODITY CHARGE .... **28¢** per M.C.F.

Minimum Monthly Charge — $10.00

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. shall be increased by 3¢ and the Gross Rate so arrived at shall apply.

OPTIONAL HIGH LOAD FACTOR RATE "C"

Effective July 1957

Availability:

To customers on annual contract whose annual consumption of gas is not less than 12,000 M.C.F., and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption for the year.

Net Rate:

FIXED CHARGE—**$20.00** per month plus
$ 1.00 per month per 1,000 cu. ft. of maximum 12-hour demand.

plus

COMMODITY CHARGE—First 2,000 M.C.F. per month—**24¢** per M.C.F.
Next 2,000 M.C.F. per month—**20¢** per M.C.F.
All additional M.C.F. per month—**17¢** per M.C.F.

Minimum Monthly Charge — Fixed Charge

Determination of Demand:

The maximum 12-hour demand shall be the greatest amount of gas in cubic feet delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods as determined by the Company by measurement. The maximum 12-hour demand of a new consumer of gas shall be estimated by the company.

Term of Contract:

This schedule is available only on annual contract, which shall continue from year to year thereafter until either party

shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year, it shall cease and determine.

AIRDRIE, BOWDEN, CARSTAIRS, CROSSFIELD, DELBURNE, DIDSBURY, INNISFAIL, OLDS AND PENHOLD

Effective November 1956

GENERAL RATE — No. 1

Availability:

Available to all customers.

Net Rate:

First 2 M.C.F. or Less per month **$2.50**
All additional M.C.F. per month .... **50¢** per M.C.F.

Minimum Monthly Charge — $2.50

General Conditions:

When accounts are not paid on or before the due date, the charge per M.C.F. other than the first two M.C.F. shall be increased by 4¢ and the Gross Rate so arrived at shall apply.

OPTIONAL RATE — No. 2

Availability:

This schedule is available to all customers using in excess of 3,350 M.C.F. per year.

Net Rate:

FIXED CHARGE .... **$35.00** per month
plus
COMMODITY CHARGE .... **38¢** per M.C.F.

Minimum Monthly Charge — $35.00

General Conditions:

1. This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year, it shall cease and determine.
2. When accounts are not paid on or before the due date, the charge per M.C.F. shall be increased by **3¢** and the Gross Rate so arrived at shall apply.

OPTIONAL RATE — No. 3

Availability:

This schedule is available to all customers using in excess of 106,000 M.C.F. per year.

Net Rate:

FIXED CHARGE .... **$300.00** per month
plus
COMMODITY CHARGE .... **35¢** per M.C.F.

Minimum Monthly Charge — $300.00

General Conditions:

This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party, at least thirty days prior to the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year, it shall cease and determine.

Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "A"

1. Edmonton, Bruce, Holden, Jasper Place, Kinsella, Ryley, Tofield, Viking.
2. Areas adjacent to Edmonton lying south of the North Saskatchewan River.
3. Areas adjacent to the following Transmission Lines: Devon, Bonnie Glen, Viking.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 3 MCF -- **$2.40** per month
All additional MCF -------------------------------- **$0.25** per MCF per month
Minimum Monthly Charge—**$2.40.**

When accounts are not paid on or before the due date, the charge per MCF other than for the First 3 MCF shall be increased by **$0.02** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

A—Available on annual contract to all consumers whose annual consumption is more than 9,670 MCF and less than 42,000 MCF.

Fixed Charge -- **$50.00** per month
All MCF -- **$ 0.19** per MCF per month
Minimum Monthly Charge—**$50.00.**

B—Available on annual contract to all consumers whose annual consumption is more than 42,000 MCF.

Fixed Charge -- **$120.00** per month
All MCF -- **$ 0.17** per MCF per month
Minimum Monthly Charge—**$120.00.**

When accounts are not paid on or before the due date, the charge per MCF under Rate No. 2A, shall be increased by **$0.02** per MCF and the gross rate so arrived at shall apply.

RATE No. 3—HIGH LOAD FACTOR

Available on annual contract to all consumers whose annual consumption is more than 12,000 MCF and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption during the contract period.

Fixed Charge: **$20.00** per month, plus **$1.75** per month per MCF of maximum 12-hour demand.

Commodity Charge: First 1,000 MCF per month -------------------------- **$0.14** per MCF
Next 1,000 MCF per month -------------------------- **$0.12** per MCF
All additional MCF per month ----------------------- **$0.10** per MCF

Minimum Monthly Charge—Fixed Charge.

The maximum 12-hour demand shall be the greatest amount of gas in cubic feet as determined by the Company, delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods.

MAIN LINE SERVICE RATE—HIGH LOAD FACTOR

Available on annual contract to all consumers whose annual consumption is more than 300,000 MCF and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption during the contract period, and who are supplied with natural gas directly from the Company's main transmission line from the Viking-Kinsella Field to the City of Edmonton, or from the Fort Saskatchewan branch transmission line at a point between the Company's main transmission line and the North Saskatchewan River.

Fixed Charge: **$20.00** per month, plus **$1.00** per month per MCF of maximum 12-hour demand.

Commodity Charge: First 1,000 MCF per month -------------------------- **$0.14** per MCF
Next 1,000 MCF per month -------------------------- **$0.12** per MCF
All additional MCF per month ----------------------- **$0.10** per MCF

Minimum Monthly Charge—Fixed Charge.

The maximum 12-hour demand shall be the greatest amount of gas in cubic feet as determined by the Company, delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. The Head Office is located at 10124 - 104 Street, Edmonton.

Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "B"

1. Bittern Lake, Blackfalds, Bon Accord, Camrose, Fort Saskatchewan, Gibbons, Hobbema, Irma, Lacombe, Legal, Mannville, Morningside, Onoway, Ponoka, Red Deer, Round Hill, St. Albert, Vermilion, Wetaskiwin.
2. Areas adjacent to Edmonton lying North of the North Saskatchewan River.
3. Areas adjacent to the following Transmission Lines: Acheson, Fort Saskatchewan-St. Albert, Legal-Fort Saskatchewan, Southern Extension, Vermilion, Wainwright Army Camp.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 3 MCF	**$2.50** per month
All additional MCF	**$0.38** per MCF per month

Minimum Monthly Charge—**$2.50**.

When accounts are not paid on or before the due date, the charge per MCF other than for the First 3 MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 741 MCF.

Fixed Charge	**$10.00** per month
All MCF	**$ 0.24** per MCF per month

Minimum Monthly Charge—**$10.00**.

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 3—HIGH LOAD FACTOR

Available on annual contract to all consumers whose annual consumption is more than 12,000 MCF and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption during the contract period.

Fixed Charge: **$20.00** per month, plus **$1.75** per month per MCF of maximum 12-hour demand.

Commodity Charge:	First 1,000 MCF per month	**$0.17** per MCF
	Next 1,000 MCF per month	**$0.15** per MCF
	All additional MCF per month	**$0.13** per MCF

Minimum Monthly Charge—Fixed Charge.

The maximum 12-hour demand shall be the greatest amount of gas in cubic feet as determined by the Company, delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

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Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "C"

1. Stony Plain, Spruce Grove.
2. Areas adjacent to the Stony Plain Transmission Line and the Distribution System West from Texaco Absorption Plant.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 2 MCF -- **$2.50** per month

All additional MCF -- **$0.55** per MCF per month

Minimum Monthly Charge—**$2.50**.

When accounts are not paid on or before the due date, the charge per MCF other than the First 2 MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 450 MCF.

Fixed Charge -- **$10.00** per month

All MCF --- **$0.32** per MCF per month

Minimum Monthly Charge—**$10.00**.

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "D"

1. Beverly, Vegreville.
2. Area adjacent to Vegreville Transmission Line.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 3 MCF -- **$2.50** per month

All additional MCF -- **$0.34** per MCF per month

Minimum Monthly Charge—**$2.50**.

When accounts are not paid on or before the due date, the charge per MCF other than the First 3 MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 852 MCF.

Fixed Charge -- **$10.00** per month

All MCF --- **$ 0.22** per MCF per month

Minimum Monthly Charge—**$10.00**.

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 3—HIGH LOAD FACTOR

Available on annual contract to all consumers whose annual consumption is more than 12,000 MCF and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40 per cent of their total consumption during the contract period.

Fixed Charge: **$20.00** per month plus **$1.75** per month per MCF of maximum 12-hour demand.

Commodity Charge: First 1,000 MCF per month ---------------------------- **$0.16** per MCF

Next 1,000 MCF per month ---------------------------- **$0.14** per MCF

All additional MCF per month ------------------------ **$0.12** per MCF

Minimum Monthly Charge—Fixed Charge.

The maximum 12-hour demand shall be the greatest amount of gas in cubic feet as determined by the Company, delivered in any twelve consecutive hours during the current billing period or the preceding eleven billing periods.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

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Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "E"

1. Bruderheim, Chipman, Hilliard, Josephburg, Lamont, Millet, Mundare.
2. Areas adjacent to Transmission Lines serving these Communities.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 2 MCF -- **$2.50** per month

All additional MCF ---------------------------------- **$0.65** per MCF per month

Minimum Monthly Charge—**$2.50.**

When accounts are not paid on or before the due date, the charge per MCF other than the First 2 MCF shall be increased by **$0.04** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose consumption is more than 542 MCF.

Fixed charge -- **$12.50** per month

All MCF --- **$ 0.40** per MCF per month

Minimum Monthly Charge—**$12.50.**

When accounts are not paid on or before due date, the charge per MCF shall be increased by **$0.03** per MCF and gross rate so arrived at shall apply.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "F"

1. Glenwood, Hinton, Innisfree, Islay, Lavoy, Minburn, Ranfurly, Sylvan Lake.
2. Areas adjacent to Transmission Lines serving these Communities.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 2 MCF -- **$3.00** per month

All additional MCF -- **$0.75** per MCF per month

Minimum Monthly Charge—**$3.00**.

When accounts are not paid on or before the due date, the charge per MCF other than the first 2 MCF shall be increased by **$0.04** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 528 MCF.

Fixed Charge -- **$12.50** per month

All MCF -- **$ 0.50** per MCF per month

Minimum Monthly Charge—**$12.50**.

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

Northwestern Utilities, Limited
Schedule of Natural Gas Rates

RATE AREA "G"

1. Edson, Entwistle, Evansburg, Wildwood.

2. Areas adjacent to North Canadian Oils Ltd. transmission line between Wabamun and Edson.

RATE No. 1—GENERAL RATE

Available to all consumers

First 2 MCF ---**$2.50** per month

All additional MCF ---------------------------------------**$0.59** per MCF per month

Minimum Monthly Charge—**$2.50**.

When accounts are not paid on or before the due date, the charge per MCF other than the first two MCF shall be increased by **$0.03** per MCF and the Gross Rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 2,890 MCF per year.

Fixed Charge ---**$35.00** per month

All MCF --**$ 0.45** per MCF per month

Minimum Monthly Charge—**$35.00**.

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the Gross Rate so arrived at shall apply.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

Northwestern Utilities, Limited

Schedule of Natural Gas Rates

RATE AREA "H"

1. Town of Drayton Valley.
2. Areas adjacent to Transmission Lines serving this Community.

RATE No. 1—GENERAL RATE

Available to all consumers.

First 2 MCF ---------- **$2.50** per month

All additional MCF ---------- **$0.48** per MCF per month

Minimum Monthly Charge—**$2.50**.

When accounts are not paid on or before the due date, the charge per MCF other than the First 2 MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

RATE No. 2—OPTIONAL RATE

Available on annual contract to all consumers whose annual consumption is more than 635 MCF.

Fixed Charge ---------- **$10.00** per month

All MCF ---------- **$ 0.32** per MCF per month

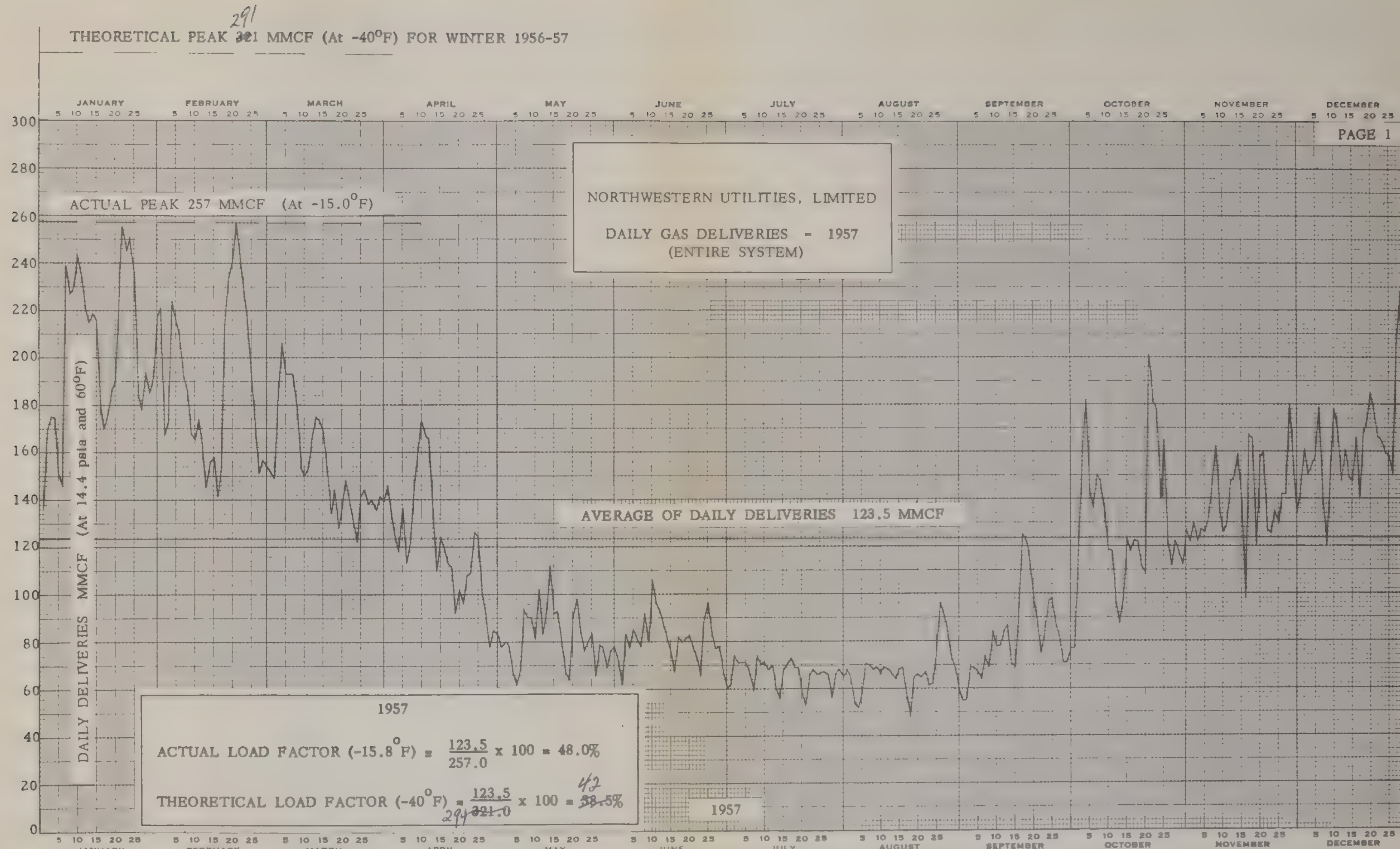
Minimum Monthly Charge—**$10.00.**

When accounts are not paid on or before the due date, the charge per MCF shall be increased by **$0.03** per MCF and the gross rate so arrived at shall apply.

All of the above rates have been approved by the Board of Public Utility Commissioners of the Province of Alberta, but are subject to regulation by that body from time to time.

Further information regarding these rates for natural gas may be obtained by contacting the Company. Head Office is located at 10124 - 104 Street, Edmonton.

NU-C124h


THEORETICAL PEAK ~~321~~ 291 MMCF (At -40°F) FOR WINTER 1956-57
ACTUAL PEAK 257 MMCF (At -15.0°F)
NORTHWESTERN UTILITIES, LIMITED
DAILY GAS DELIVERIES - 1957
(ENTIRE SYSTEM)
AVERAGE OF DAILY DELIVERIES 123.5 MMCF
DAILY DELIVERIES MMCF (At 14.4 psia and 60°F)
JANUARY
FEBRUARY
MARCH
APRIL
MAY
JUNE
JULY
AUGUST
SEPTEMBER
OCTOBER
NOVEMBER
DECEMBER
1957
1957
ACTUAL LOAD FACTOR (-15.8°F) = $\frac{123.5}{257.0}$ x 100 = 48.0%
THEORETICAL LOAD FACTOR (-40°F) = $\frac{123.5}{\cancel{321.0}\ 291}$ x 100 = ~~38.5~~ 42%

ANNUAL MARKET REQUIREMENTS AND PEAK DAY LOADS

1957 - 1986

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
CALGARY, ALBERTA

and

NORTHWESTERN UTILITIES, LIMITED
EDMONTON, ALBERTA

As prepared for

Oil and Gas Conservation Board

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

and

NORTHWESTERN UTILITIES, LIMITED

Annual Market Requirements and Peak Day Loads
1957 - 1986

The present estimates have been prepared on a similar basis to previous estimates prepared on various occasions between December 30, 1948 and June 27, 1953, which were presented at former hearings before the Petroleum and Natural Gas Conservation Board, and subsequent revisions presented informally to the Board. The main difference between these present estimates and the most recent previous ones is an upward revision of population estimates as a result of later Dominion and Civic census data, and revision in the estimates of additional large industrial load.

The basic method adopted for each company is to project populations for each of the systems, and apply to these estimates factors of customers per hundred of population and Mcf sales per customer in each of the classes, Domestic, Commercial and Basic Industrial, which factors are projected from past experience. To the resulting totals are added estimates for special industrial loads and the grand totals are then adjusted to a field measurement basis of 14.4 psia and 60° F. The attached graphs, Figures 1 to 9, indicate the projections of population, customers per hundred, and sales per customer for each company.

CANADIAN WESTERN

Figure 1 shows the populations of the entire system, Metropolitan Calgary and the remaining communities on the system. The population of Metropolitan Calgary, comprising Calgary proper, Bowness, Montgomery, Forest Lawn and other unincorporated fringe areas, increased from 122,777 in 1950 to 194,459 in 1956 -- an annual increase of just under 12,000 per year. The 1957 census data gave a population of 209,000, and estimates made earlier this year for Company internal purposes for the next three years were 220,000, 229,000 and 240,000 respectively. These figures were retained and an annual increase of 12,000 applied from 1960 throughout the forecast period, resulting in an estimated population in 1986 of 552,000. This linear projection represents a continuously declining annual rate of growth from 5.0% for the period 1960-61 to 2.2% for the period 1985-86. The equivalent overall compound annual growth rate for the period 1960-1986 is 3.25%

The population of the remaining city and towns on the system in 1951 was 41,116 and in 1956, for the same communities as in 1951, was 60,431 -- an annual increase of just under 4,000. In 1955 and 1956 service was extended to an unusually large number (21) of new communities, bringing the population, including these additions, to 72,000 in 1957. For the next three years, estimated populations, including provision for service to still other new communities, are 78,000, 84,000 and 89,000 respectively. Subsequent to 1960 an annual increase of 4,000 has been added throughout the forecast period resulting in an estimated population in 1986 of 193,000. This corresponds to a growth rate of 4.5% in 1960-61 and 2.1% in 1985-86 or an overall compound rate of 3.02% for the period 1960-1986.

Figures 2 to 4 show average customers per 100 population and sales per customer in the various customer classifications -- Domestic, Commercial and Basic Industrial (i.e. exclusive of special industrial loads). The points up to 1956 represent actual experience after adjustment of sales data to a basis of long-term normal temperatures to eliminate the variation due to the effect of colder or warmer than normal weather on gas sales. Also, in the years 1955 and 1956, adjustments were made in respect to the unusually large number of new communities served. In serving new communities, the populations are added to system totals in the year in which service is begun, but sales and customers are low initially, due to the time required for build up, which may take several years. Since the figures for 1957 are affected by the communities added in 1955-1956, and since still further new communities are expected to be added in 1958 and 1959, the number of customers and Mcf sales for the years 1957, 1958 and 1959, have been estimated in detail rather than by application of the overall factor of customers per 100 of population and sales per customer. These factors, however, have been applied subsequent to 1959.

In Figure 2, the plot of domestic customers per 100 of population rose rapidly from 1950 to 1953, then fell in 1954, followed by a more modest increase in 1955 and 1956. The decline in 1954, it is felt, was due to the availablity for the first time, in years between the Dominion census, of accurate population data, as a result of the requirement for a civic census to be taken in cities and towns in connection with provincial grants. The estimates of increased population in the between census years of 1952 and 1953 are considered to be unrealistically low, and consequently, the figures of customers per 100 of population to be correspondingly high. The more modest upward trend from 1951 through 1954 to 1956 is taken as accurate, and since this trend appears to be levelling off by 1956, the 1956 value of 23.3 has been projected.

With respect to domestic sales per customer, the value of 207.5 Mcf in 1952 marks the low point in the post-war decline from a high of 221 in 1945, which was caused by war-time crowding. This decline was arrested only in 1951. Following 1952 there has been an upward trend which appeared

in 1956 to be levelling off. For subseuquent years, this upward trend has been projected to 214 Mcf per customer in 1963, remaining constant at that level throughout the balance of the forecast period.

Figure 3 shows similar data in respect to commercial customers and sales. As in the case of domestic, the 1953 figure of average customers per 100 population is considered to be unrealistically high and the trend is felt to be more properly reflected from a value in 1951 of 2.6, to 2.4 in 1954, followed by a decline at a lesser rate to 2.32 in 1956. The present increased tempo of commercial construction is expected to arrest this decline and the projection has been made on a basis of 2.3 customers per 100 of population.

With respect to sales per customer, the values have increased steadily from a post-war low in 1947 as a result of larger than average sized commercial installations. This trend is estimated to continue in the light of present developments to 1,300 Mcf in 1960 and remain constant at that level thereafter.

Data for industrial customers and sales, exclusive of large special industrial loads, is plotted in Figure 4. The gradual decline in customers per 100 of population from .072 in 1951 to .069 in 1954, .067 in 1955 and .062 in 1956, is expected to level off and the projection has been made on the basis of .062 customers per 100 of population.

As in the case of commercial, basic industrial sales per customer have increased steadily from post-war lows in the period 1946-1949 and this trend is projected to a level of 35,000 Mcf in 1960, remaining constant at that level for the balance of the forecast period.

Special Industrial Loads

Separate provision has been made in the estimates for sales to the three largest industrial customers on the system, which sales amounted to 9,701,000 Mcf in 1956 and have been estimated at 9,764,000 Mcf for 1957 and 9,770,000 Mcf for 1958 and 1959. Provision has been made for an increase in one of these loads in 1960 from 2,200,000 Mcf to 4,000,000 Mcf to reflect a substantial plant expansion presently underway, bringing the total for the three to 11,570,000 Mcf. These loads have been projected throughout the remainder of the forecast period at this level.

Contingency Provision for New Large Industrial Loads

Commencing in 1958, provision has been made for sales to additional large industrial plants, at present unknown, in the amounts of 500,000 Mcf in 1958, 1,000,000 Mcf in 1959 and increasing 1,000,000 Mcf each year

thereafter. It will be noted, in connection with Special Industrial Loads, that apart from the known expansion of one of these, there is no provision for any further increase in major industrial consumption. Without the contingency provision, therefore, a constantly declining per capita consumption for large industrial use, would be projected. In view of present and probable developments in the province, this, in our view, would be unrealistic.

Sample Computation

An example of the computations for the year 1960 is given below.

Estimated population of Metropolitan Calgary	240,000	
Estimated population of towns	89,000	
Estimated total population	329,000	
Domestic		
Customers per 100 of population	23.3	
Mcf sales per customer	213.7	
Total Domestic sales	16,382,000	Mcf
Commercial		
Customers per 100 of population	2.30	
Mcf sales per customer	1,300	
Total Commercial sales	9,837,000	Mcf
Basic Industrial		
Customers per 100 of population	.062	
Mcf sales per customer	35,000	
Total Basic Industrial sales	7,140,000	Mcf
Special Industrial Sales	11,570,000	Mcf
Contingency for New Industrial Loads	2,000,000	Mcf
Total System sales	46,929,000	Mcf
Field Requirements @ 14.4 psia & 60° F.	45,540,000	Mcf(1)

Note: (1) Field requirements @ 14.4 psia & 60° F. are calculated by the application of a factor of 96.65%, derived from recent experience, to all sales, with the exception of one Special Industrial load of 3,500,000 Mcf, which is measured under a special contract at 14.4 psia & 60° F, and the contingency provision for new industrial loads, which are also assumed to be measured at 14.4 psia & 60° F.

Per Capita Consumption

Since the Board has, in the past, made various calculations and projections on the basis of per capita consumptions and trends of the same, the following tabulation is given of per capita consumptions as projected in this submission. These data are the combination of the basic factors of customers per 100 of population and sales per customer as projected from 1960 for Domestic, Commercial and Basic Industrial sales. The per capita consumptions for special industrial loads and the contingency provision for new large industrial loads are arrived at by dividing the sales estimates by total system population.

			Per Capita Consumption - Mcf				
Year	Dom.	Com.	Basic Ind.	Spcls.	Cont.	Total Ind.	Total System Sales
1957	48.6	28.9	20.5	34.8	-	55.3	132.8
1960	49.8	29.9	21.7	35.2	6.1	63.0	142.7
1970	49.8	29.9	21.7	23.7	24.5	69.9	149.6
1980	49.8	29.9	21.7	17.8	33.9	73.4	153.1
1986	49.8	29.9	21.7	15.5	37.6	74.8	154.5

Domestic per capita consumption rose from 47.6 Mcf in 1951 to 48.2 in 1954, and, after adjusting for the effect of new communities added, to 49.6 in 1956. Ignoring the figure for 1957 in the tabulation above, which is not adjusted for the effect of new towns added, a further increase to 49.8 Mcf in 1960 and thereafter is projected.

Commercial per capita consumption was 28.4 Mcf in 1951, increasing to 29.0 in 1954 and 1956, and is projected to rise to 29.9 Mcf in 1960 and thereafter.

The corresponding figures for basic industrial consumption were 18.2 Mcf in 1951, rising to 19.8 in 1954 and 20.4 in 1956. The projected increase to 21.7 Mcf in 1960 and thereafter represents a further 6% rise above the 1956 level which is considered reasonable.

Per capita consumption of the three special industrial loads fell from 43.9 Mcf in 1951 to 40.0 in 1954 and 38.1 in 1956. Apart from the temporary increase in 1960, due to the provision for increase in one of these loads, the projected per capita consumption continues to

decline over the forecast period to a level in 1986 less than half that in 1957. A substantial portion of the contingency provision for new industrial loads is therefore required, in effect, to offset this decline, the balance bringing about an increase in total industrial per capita consumption in 1986 to a level about 35% higher than in 1957. This is considered to be realistic in view of the present trend of increasing industrialization in the province.

The overall figure of total system sales per capita, as projected, rises from 132.8 Mcf in 1957 to 154.5 Mcf in 1986, an increase of approximately 16%.

Peak Day Loads

Potential peak day loads for the system, at field measurement base conditions of 14.4 psia & 60° F., on the basis of the most severe conditions of temperature which it is expected will occur have been calculated by applying to the total Domestic, Commercial and Basic Industrial sales a factor of 0.771%, being the relationship between year-end peak day loads and annual sales derived from past experience. This is equivalent to a load factor of 35.6%.(1) To the resulting figure has been added the peak day load and for each of the present special industrial loads based on current experience, and provisions for the future additional industrial loads at 85% load factor, which is the average of the present special industrial loads.

Statements

Statements summarizing all the above material are included in this submission immediately following this text. The first statement shows for Canadian Western a breakdown of total system market requirements at sales measurement conditions as arrived at from the foregoing detailed procedure.

The second statement shows a corresponding breakdown of annual market requirements by Domestic, Commercial and Industrial classifications, adjusted to field measurement conditions. On this statement, the contingency provision for new industrial loads has been included with special industrial.

Note: (1) This ignores the difference in measurement base conditions between sales and field outputs, the latter being at 14.4 psia & 60° F. Reflecting this difference, the load factor would be more correctly stated as 34.4%.

The third statement shows peak day loads, calculated as described above. Figures of Total System annual sales on a field measurement basis have been repeated in the second last column and corresponding overall system load factors are shown in the last column.

NORTHWESTERN UTILITIES

The estimated market requirements and peak day loads for the Northwestern Utilities system were arrived at by a similar process to that described in detail for the Canadian Western system. The following are a few brief comments in respect to the data shown for Northwestern on the graphs, Figures 5 to 9 inclusive.

1. The population of Metropolitan Edmonton shown on Figure 6 at the time of the Civic Census this spring was 271,050, an increase of approximately 93,000 from 1951, or an annual increase for the six-year period of 15,500. This amount of annual increase has been projected over the forecast period. It represents a rate of growth of 5.7% for the period 1957-1958, declining to 2.2% for the period 1985-1986, or an overall average annual rate of growth of 3.43% for the 29-year period 1957-1986.

2. The population of the remaining communities served rose more rapidly than normal from 45,000 in 1955 to 59,730 in 1957 and an estimated 67,300 in 1958, due to the extension of service to an unusually large number of new communities in this period. The projection from 1958 has been made on the basis of an average increase of 3,500 in the 5-year period 1950 to 1955. This represents a rate of growth of 5.2% for 1958-1959, declining to 2.2% for 1985-1986, or an overall average of 3.25% for the 29-year period 1958-1987.

3. The combined populations for the entire system are shown on Figure 5.

4. The factors of annual sales per customer and customers per 100 of population in each of the classes, Domestic and Commercial (exclusive of three special commercial customers) are shown on Figures 7 and 8 respectively. Data up to 1956 represent actual experience adjusted only, in the case of sales, for the effect of abnormal temperatures, while the points for 1957 are derived from a carefully prepared Gas

Sales Budget. As in the case of Canadian Western, the effect of the large number of new communities added in 1956 and 1957 distorts the plot of customers per 100 of population in those years. However, in this case, no attempt has been made to adjust for this. In the case of Domestic, there has been a continuous increase in the number of customers per 100 of population since the war and this is expected to continue to a level of 20.4 by 1962, following which it has been maintained at that level. As regards commercial customers per 100 of population, the increase since the war appears to have levelled off, apart from the distorting effect of new towns referred to above. This factor has been estimated at 2.25 for 1957, and 2.28 for 1958 and subsequent years. Domestic and Commercial sales per customer have varied in recent years over quite a narrow range and the projections as shown are at a constant level consistent with recent experience.

5. In the case of industrial sales, exclusive of the 8 largest industrial customers, provision for which is made separately under Special Industrial, a departure from past procedure has been made. In this case, industrial sales have been plotted on a per capita basis against total system population, as shown on Figure 9. As in the case of Canadian Western, the present increasing trend is expected to continue for a few years and has then been levelled off at a value of 11.0 Mcf for the remainder of the forecast period.

Requirements for Special Loads

In the case of Northwestern, provision has been made for three existing large commercial loads in a special category apart from the basic commercial sales derived from application of the factors shown on the graph, Figure 8. These figures have been projected at the 1957 level of 1,580,000 Mcf.

Provision for eight existing special industrial loads has also been made separately. In the case of several of these loads, minor variations from 1957 consumptions have been made in the early years of the projection on the basis of present information. Apart from this, sales have been projected at a constant level over the forecast period for all but one of the loads. The exception is the largest single load on the system, namely, the City of Edmonton power plant, where provision has been made for increased consumption from year to year over the entire period, although at a declining rate, consistent with the basic consumption in respect to the population of Metropolitan Edmonton. This is almost entirely responsible for the increase shown on Statement 4 for this group, from 17,070,000 Mcf in 1957 to 32,060,000 Mcf in 1986.

Contingency Provision for New Industry

As in the case of Canadian Western, provision has been made for further large industrial loads in an amount of 1,000,000 Mcf in 1959, increasing by 2,000,000 Mcf per year until 1969, 1,500,000 Mcf per year from 1970 to 1975, and 1,100,000 Mcf per year thereafter. This provision is larger than in the case of Canadian Western, as a reflection of present industrial trends in the Edmonton area.

Per Capita Consumption

The following tabulation shows the per capita consumption as projected in the various classifications:

Per Capita Consumption - Mcf

Year	Dom.	Com. (Total)	Basic. Ind.	Spcls.	Cont.	Total Ind.	Total System Sales
1957	45.3	39.5	10.4	51.6	-	62.0	146.8
1960	47.5	39.3	10.9	51.0	7.7	69.6	156.4
1970	47.9	38.0	11.0	48.9	38.7	98.6	184.5
1980	47.9	37.4	11.0	40.4	46.0	97.4	182.7
1986	47.9	37.1	11.0	36.2	47.5	94.7	179.7

Domestic per capita consumptions rose from 43.2 Mcf in 1953 to 45.6 Mcf in 1956 and has been projected to rise further to 47.9 Mcf by 1962, remaining constant at that level thereafter.

In the case of Commercial, exclusive of the three special loads, per capita consumption was 35.4 Mcf in 1953, 37.1 Mcf in 1954, declining to 35.3 Mcf in 1956. Following the temporary reduction in 1957, due to the effect of new towns, it has been projected at the 1956 level of 35.3 Mcf. The provision of a steady consumption for the Special Commercial loads is equivalent to a declining per capita consumption from 4.8 Mcf in 1957 to 1.8 Mcf in 1986. Total Commercial per capita consumption thus declines gradually from 39.5 Mcf in 1957 to 37.1 Mcf in 1986.

The projection of Basic Industrial per capita consumption is as shown on Figure 9. As regards the Special Industrial loads, even with the substantial provision for increase in the City of Edmonton power plant load, per capita consumption remains fairly constant until 1969, then declines over the balance of the forecast period. The substantial contingency provision for new industrial loads, after offsetting this decline in Special Inudstrial per capita consumption, has the effect of increasing Total Industrial per capita consumption from 62.0 Mcf in 1957 to 98.6 in 1970, declining to 94.7 Mcf in 1986. The 1986 value is 53% above that in 1957.

Total system per capita consumption increases from 146.8 Mcf in 1957 to 184.5 Mcf in 1970, following which it falls to 179.7 Mcf in 1986, approximately 22% above the 1957 level. This compares with an overall increase of 16% in the case of Canadian Western, and is considered to be a realistic reflection of the greater industrial potential in the Edmonton area.

Field Measurement Basis

Adjustment of the total sales figures (including the contingency provision for new industrial loads) to a field measurement basis of 14.4 psia & 60° F. has been made by applying a factor of 97.8%, which is consistent with sales measurement conditions of 13.82 psia (4 ounces above Edmonton atmospheric pressure) and 50° F.

Peak Day Loads

Peak day loads have been derived in a similar manner as those for Canadian Western, the factor applicable to basic sales being 0.782% which is equivalent to a load factor of about 35%. Peak loads for each of the existing special customers have been calculated on the basis of current experience and for future new special industrial loads, at a load factor of 85%.

Statements

The statements for Northwestern Utilities will be found immediately following those for Canadian Western. They have been prepared on a similar basis and are numbered No. 4, 5 and 6 respectively. It should be noted that all sales figures for Northwestern Utilities are on the basis of Kinsella heating values.

Statement 1

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Projection of Domestic, Commercial, Basic Industrial and Special Industrial Sales

1957 - 1986

Year	Domestic Sales MMCF (a)	Commercial Sales MMCF (b)	Basic Industrial Sales MMCF (c)	Special Industrial Sales MMCF (d)	Sub Total MMCF (e)	Contingency for new Ind. Loads MMCF (f)	Total Sales MMCF (g)	Total Sales at 14.4 psia & 60° F. BCF (h)
1957	13,658	8,131	5,765	9,764	37,318	-	37,318	36.2
58	14,509	8,593	6,210	9,770	39,082	500	39,582	38.4
59	15,352	9,186	6,620	9,770	40,928	1,000	41,928	40.7
1960	16,382	9,837	7,140	11,570	44,929	2,000	46,929	45.5
61	17,186	10,316	7,490	11,570	46,562	3,000	49,562	48.1
62	17,992	10,794	7,840	11,570	48,196	4,000	52,196	50.7
63	18,798	11,272	8,190	11,570	49,830	5,000	54,830	53.3
64	19,596	11,751	8,540	11,570	51,457	6,000	57,457	55.9
65	20,394	12,229	8,890	11,570	53,083	7,000	60,083	58.4
66	21,191	12,708	9,205	11,570	54,674	8,000	62,674	61.0
67	21,989	13,186	9,555	11,570	56,300	9,000	65,300	63.5
68	22,787	13,664	9,905	11,570	57,926	10,000	67,926	66.1
69	23,585	14,143	10,255	11,570	59,553	11,000	70,553	68.7
1970	24,383	14,621	10,605	11,570	61,179	12,000	73,179	71.3
71	25,180	15,100	10,955	11,570	62,805	13,000	75,805	73.8
72	25,978	15,578	11,305	11,570	64,431	14,000	78,431	76.4
73	26,776	16,056	11,655	11,570	66,057	15,000	81,057	79.0
74	27,574	16,535	12,005	11,570	67,684	16,000	83,684	81.5
75	28,371	17,013	12,355	11,570	69,309	17,000	86,309	84.1
76	29,169	17,492	12,705	11,570	70,936	18,000	88,936	86.7
77	29,967	17,970	13,055	11,570	72,562	19,000	91,562	89.3
78	30,765	18,448	13,405	11,570	74,188	20,000	94,188	91.8
79	31,563	18,927	13,720	11,570	75,780	21,000	96,780	94.4
1980	32,360	19,405	14,070	11,570	77,405	22,000	99,405	96.9
81	33,158	19,884	14,420	11,570	79,032	23,000	102,032	99.5
82	33,956	20,362	14,770	11,570	80,658	24,000	104,658	102.1
83	34,754	20,840	15,120	11,570	82,284	25,000	107,284	104.6
84	35,552	21,319	15,470	11,570	83,911	26,000	109,911	107.2
85	36,349	21,797	15,820	11,570	85,536	27,000	112,536	109.8
1986	37,147	22,276	16,170	11,570	87,163	28,000	115,163	112.4

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Projection of Annual Market Requirements by Classification
(14.4 psia and 60° F.)

Billions of Cubic Feet

Year	Domestic (a)	Commercial (b)	Basic Industrial (c)	Special Industrial & Contingency (d)	Total Field Sendout (e)
1957	13.20	7.86	5.57	9.57	36.2
58	14.02	8.31	6.00	10.07	38.4
59	14.84	8.88	6.40	10.58	40.7
1960	15.83	9.51	6.90	13.26	45.5
61	16.61	9.97	7.24	14.28	48.1
62	17.39	10.43	7.58	15.30	50.7
63	18.17	10.89	7.92	16.32	53.3
64	18.94	11.36	8.25	17.35	55.9
65	19.71	11.82	8.59	18.28	58.4
66	20.48	12.28	8.90	19.34	61.0
67	21.25	12.74	9.24	20.27	63.5
68	22.02	13.21	9.57	21.30	66.1
69	22.79	13.67	9.92	22.32	68.7
1970	23.57	14.13	10.25	23.35	71.3
71	24.34	14.59	10.59	24.28	73.8
72	25.11	15.06	10.93	25.30	76.4
73	25.88	15.52	11.26	26.34	79.0
74	26.65	15.98	11.60	27.27	81.5
75	27.42	16.44	11.94	28.30	84.1
76	28.19	16.91	12.28	29.32	86.7
77	28.96	17.37	12.62	30.35	89.3
78	29.73	17.83	12.95	31.29	91.8
79	30.51	18.29	13.26	32.34	94.4
1980	31.28	18.75	13.60	33.27	96.9
81	32.05	19.22	13.94	34.29	99.5
82	32.82	19.68	14.27	35.33	102.1
83	33.59	20.14	14.61	36.26	104.6
84	34.36	20.60	14.95	37.29	107.2
85	35.13	21.07	15.29	38.31	109.8
1986	35.90	21.53	15.63	39.34	112.4
Totals	740.74	444.04	322.05	740.47	2247.3

Note: Special Industrial & Contingency was rounded off to bring the Total Field Sendout to the nearest tenth of a billion cubic feet.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Estimated Year End Peak Requirements - 1957 - 1986

Year	Total System Less Special Industrial & Contingency MMCF/D (a)	Special Industrial Daily Peak MMCF/D (b)	Contingency for New Industrial Loads (85% L.F.) MMCF/D (c)	Total System Daily Peak MMCF/D (d)	Total System Annual Sales (BCF) (e)	Load Factor (f)
1957	212.5	30.5	-	243	36.2	40.8
58	226.0	30.5	1.5	258	38.4	40.7
59	240.0	30.5	3.5	274	40.7	40.7
1960	257.0	37.0	6.0	300	45.5	41.6
61	270.0	37.0	9.0	316	48.1	41.7
62	282.0	37.0	12.0	331	50.7	41.9
63	295.0	37.0	15.0	347	53.3	42.0
64	307.0	37.0	19.0	363	55.9	42.1
65	320.0	37.0	22.0	379	58.4	42.2
66	332.0	37.0	25.0	394	61.0	42.3
67	345.0	37.0	28.0	410	63.5	42.5
68	357.0	37.0	32.0	426	66.1	42.5
69	370.0	37.0	35.0	442	68.7	42.6
1970	382.0	37.0	38.0	457	71.3	42.7
71	395.0	37.0	41.0	473	73.8	42.7
72	407.0	37.0	45.0	489	76.4	42.8
73	420.0	37.0	48.0	505	79.0	42.8
74	433.0	37.0	51.0	521	81.5	42.8
75	445.0	37.0	54.0	536	84.1	42.9
76	458.0	37.0	58.0	553	86.7	42.9
77	470.0	37.0	61.0	568	89.3	43.0
78	483.0	37.0	64.0	584	91.8	43.0
79	495.0	37.0	67.0	599	94.4	43.1
1980	507.0	37.0	71.0	615	96.9	43.1
81	520.0	37.0	74.0	631	99.5	43.1
82	533.0	37.0	77.0	647	102.1	43.3
83	545.0	37.0	80.0	662	104.6	43.3
84	558.0	37.0	84.0	679	107.2	43.4
85	570.0	37.0	87.0	694	109.8	43.4
1986	583.0	37.0	90.0	710	112.4	43.4

All figures at 14.4 psia and 60° F.

Statement 4

NORTHWESTERN UTILITIES, LIMITED

Projection of N.U.L.'s Domestic, Commercial, Special Commercial, Industrial and Special Industrial Sales

1957 - 1986

Year	Domestic Sales MMCF (a)	Commercial Sales MMCF (b)	Industrial Sales MMCF (c)	Special Commercial Sales MMCF (d)	Special Industrial Sales MMCF (e)	System Sales 13.82 & 50° MMCF (f)	Contingency For New Ind. Loads BCF (g)	Total System Sales 13.82&50° BCF (h)	Total System Sales 14.4&60° BCF (i)	Cumulativ Sales BCF (j)
1957	14,990	11,470	3,440	1,580	17,070	48,550	-	48.6	47.6	47.6
1958	16,440	12,510	3,780	1,580	17,450	51,760	-	51.7	50.6	98.2
1959	17,550	13,180	4,040	1,580	18,810	55,160	1.0	56.2	55.0	153.2
1960	18,620	13,850	4,290	1,580	19,970	58,310	3.0	61.3	60.0	213.2
1961	19,650	14,520	4,520	1,580	20,930	61,200	5.0	66.2	64.8	278.0
1962	20,610	15,190	4,730	1,580	22,150	64,260	7.0	71.3	69.8	347.8
1963	21,520	15,860	4,940	1,580	22,660	66,560	9.0	75.6	74.0	421.8
1964	22,430	16,530	5,150	1,580	23,610	69,300	11.0	80.3	78.6	500.4
1965	23,340	17,200	5,360	1,580	24,560	72,040	13.0	85.0	83.2	583.6
1966	24,250	17,880	5,560	1,580	25,510	74,780	15.0	89.8	87.9	671.5
1967	25,160	18,550	5,770	1,580	26,460	77,520	17.0	94.5	92.5	764.0
1968	26,070	19,220	5,980	1,580	27,360	80,210	19.0	99.2	97.1	861.1
1969	26,980	19,890	6,190	1,580	28,150	82,790	21.0	103.8	101.6	962.7
1970	27,890	20,560	6,400	1,580	28,460	84,890	22.5	107.4	105.1	1067.8
1971	28,810	21,230	6,610	1,580	28,860	87,090	24.0	111.1	108.8	1176.6
1972	29,720	21,910	6,820	1,580	29,260	89,290	25.5	114.8	112.4	1289.0
1973	30,630	22,580	7,030	1,580	29,510	91,330	27.0	118.3	115.8	1404.8
1974	31,540	23,230	7,240	1,580	29,760	93,350	28.5	121.9	119.3	1524.1
1975	32,450	23,920	7,450	1,580	30,010	95,410	30.0	125.4	122.8	1646.9
1976	33,360	24,590	7,650	1,580	30,260	97,440	31.1	128.5	125.8	1772.7
1977	34,270	25,260	7,860	1,580	30,510	99,480	32.2	131.7	128.9	1901.6
1978	35,180	25,940	8,070	1,580	30,760	101,530	33.3	134.8	132.0	2033.6
1979	36,090	26,610	8,280	1,580	30,960	103,520	34.4	137.9	135.0	2168.6
1980	37,000	27,280	8,490	1,580	31,160	105,510	35.5	141.0	138.0	2306.6
1981	37,910	27,950	8,700	1,580	31,310	107,450	36.6	144.1	141.1	2447.7
1982	38,820	28,620	8,910	1,580	31,460	109,390	37.7	147.1	144.0	2591.7
1983	39,740	29,290	9,120	1,580	31,610	111,340	38.8	150.1	146.9	2738.6
1984	40,650	29,960	9,330	1,580	31,760	113,280	39.9	153.2	150.0	2888.6
1985	41,560	30,630	9,540	1,580	31,910	115,220	41.0	156.2	152.9	3041.5
1986	42,470	31,310	9,740	1,580	32,060	117,160	42.1	159.3	156.0	3197.5

NORTHWESTERN UTILITIES, LIMITED

Projection of Annual Market Requirements by Classification
(14.4 psia and 60° F.)

Billions of Cubic Feet

Year	Domestic (a)	Commercial (b)	Basic Industrial (c)	Special Industrial & Contingency (d)	Total Field Sendout (e)
1957	14.67	12.77	3.37	16.79	47.6
58	16.09	13.79	3.70	17.02	50.6
59	17.17	14.44	3.95	19.44	55.0
1960	18.22	15.10	4.20	22.48	60.0
61	19.23	15.75	4.42	25.40	64.8
62	20.17	16.41	4.63	28.59	69.8
63	21.06	17.06	4.83	31.05	74.0
64	21.95	17.72	5.04	33.89	78.6
65	22.84	18.38	5.24	36.74	83.2
66	23.73	19.04	5.44	39.69	87.9
67	24.62	19.70	5.65	42.53	92.5
68	25.51	20.35	5.85	45.39	97.1
69	26.40	21.01	6.06	48.13	101.6
1970	27.29	21.66	6.26	49.89	105.1
71	28.19	22.32	6.47	51.82	108.8
72	29.08	22.98	6.67	53.67	112.4
73	29.97	23.64	6.88	55.31	115.8
74	30.86	24.28	7.08	57.08	119.3
75	31.75	24.95	7.29	58.81	122.8
76	32.64	25.61	7.49	60.06	125.8
77	33.53	26.26	7.69	61.42	128.9
78	34.42	26.93	7.90	62.75	132.0
79	35.31	27.58	8.10	64.01	135.0
1980	36.20	28.24	8.31	65.25	138.0
81	37.09	28.90	8.51	66.60	141.1
82	37.99	29.55	8.72	67.74	144.0
83	38.89	30.21	8.92	68.88	146.9
84	39.78	30.86	9.13	70.23	150.0
85	40.67	31.52	9.33	71.38	152.9
1986	41.56	32.18	9.53	72.73	156.0
Totals	856.88	679.19	196.66	1464.77	3197.5

Note: Special Industrial & Contingency was rounded off to bring the Total Field Sendout to the nearest tenth of a billion cubic feet.

NORTHWESTERN UTILITIES, LIMITED

Estimated Year End Peak Requirements -- 1957-1986

Year	Total System Less Special Ind. and Contingency Year End Daily Peak MMCFD (a)	Special Industrial Daily Peak MMCFD (b)	Contingency for New Ind. Loads Daily Peak (85% L.F.) MMCFD (c)	Total System Daily Peak MMCFD (d)	Total System Annual Sales BCF (e)	Load Factor (f)
1957	246	71	-	317	47.6	41.1
1958	268	73	-	341	50.6	40.6
1959	284	85	3	372	55.0	40.5
1960	300	88	10	398	60.0	41.3
1961	315	93	16	424	64.8	41.9
1962	330	98	23	451	69.8	42.4
1963	343	99	29	471	74.0	43.0
1964	358	103	35	496	78.6	43.4
1965	372	108	42	522	83.2	43.7
1966	386	112	48	546	87.9	44.1
1967	400	117	55	572	92.5	44.3
1968	414	120	61	595	97.1	44.7
1969	428	119	68	615	101.6	45.3
1970	442	122	73	637	105.1	45.2
1971	456	124	77	657	108.8	45.4
1972	470	126	82	678	112.4	45.4
1973	484	128	87	699	115.8	45.4
1974	498	130	92	720	119.3	45.4
1975	512	127	97	736	122.8	45.7
1976	526	129	100	755	125.8	45.7
1977	540	131	104	775	128.9	45.6
1978	554	133	107	794	132.0	45.5
1979	568	134	111	813	135.0	45.5
1980	582	136	114	832	138.0	45.4
1981	596	133	118	847	141.1	45.6
1982	610	134	122	866	144.0	45.6
1983	624	135	125	884	146.9	45.5
1984	638	137	129	904	150.0	45.5
1985	652	138	132	922	152.9	45.4
1986	666	139	136	941	156.0	45.4

All figures at 14.4 psia & 60° F.   Kinsella Heating Basis

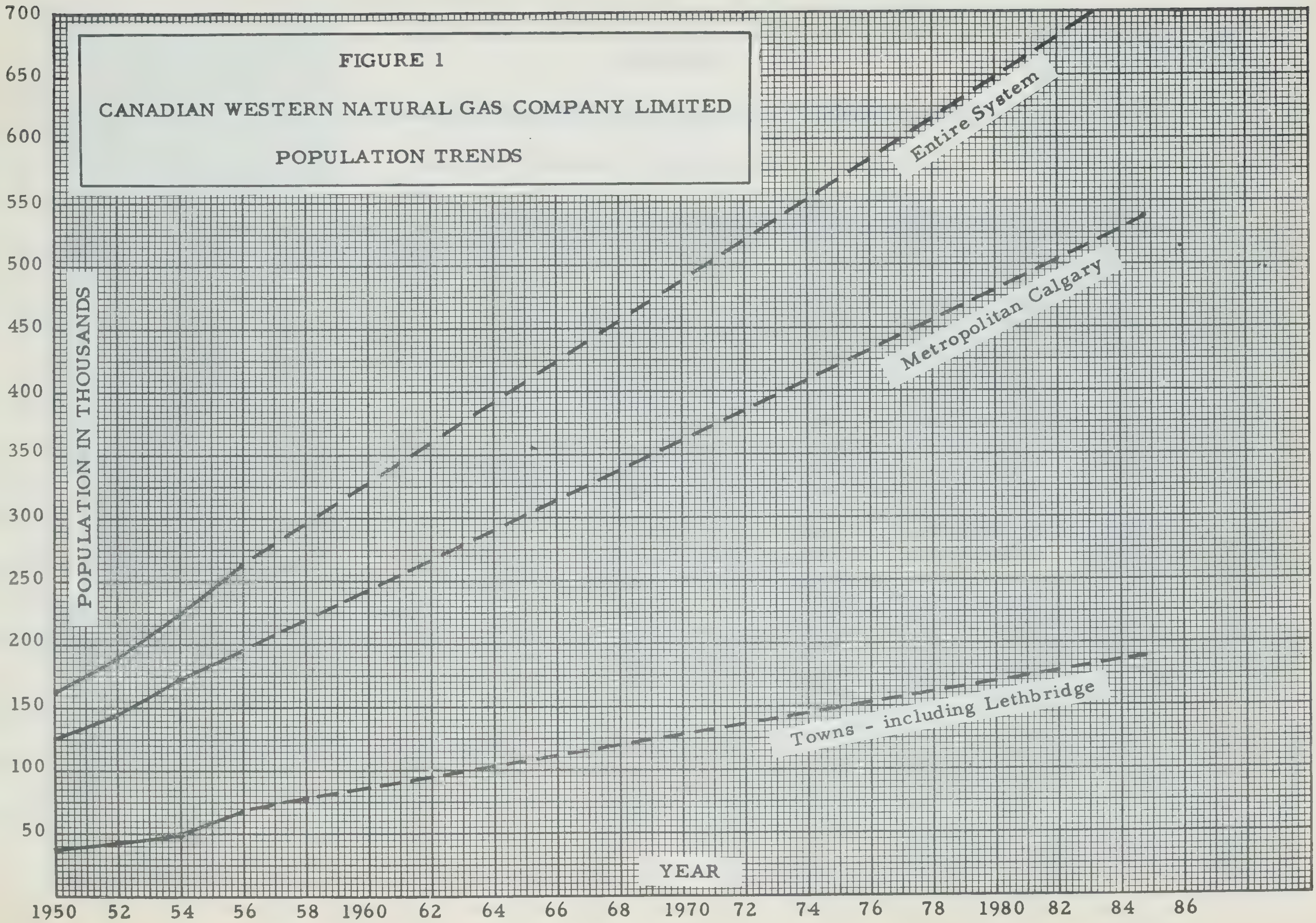


FIGURE 1
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
POPULATION TRENDS
Entire System
Metropolitan Calgary
Towns - including Lethbridge
POPULATION IN THOUSANDS
YEAR
700
650
600
550
500
450
400
350
300
250
200
150
100
50
1950
52
54
56
58
1960
62
64
66
68
1970
72
74
76
78
1980
82
84
86

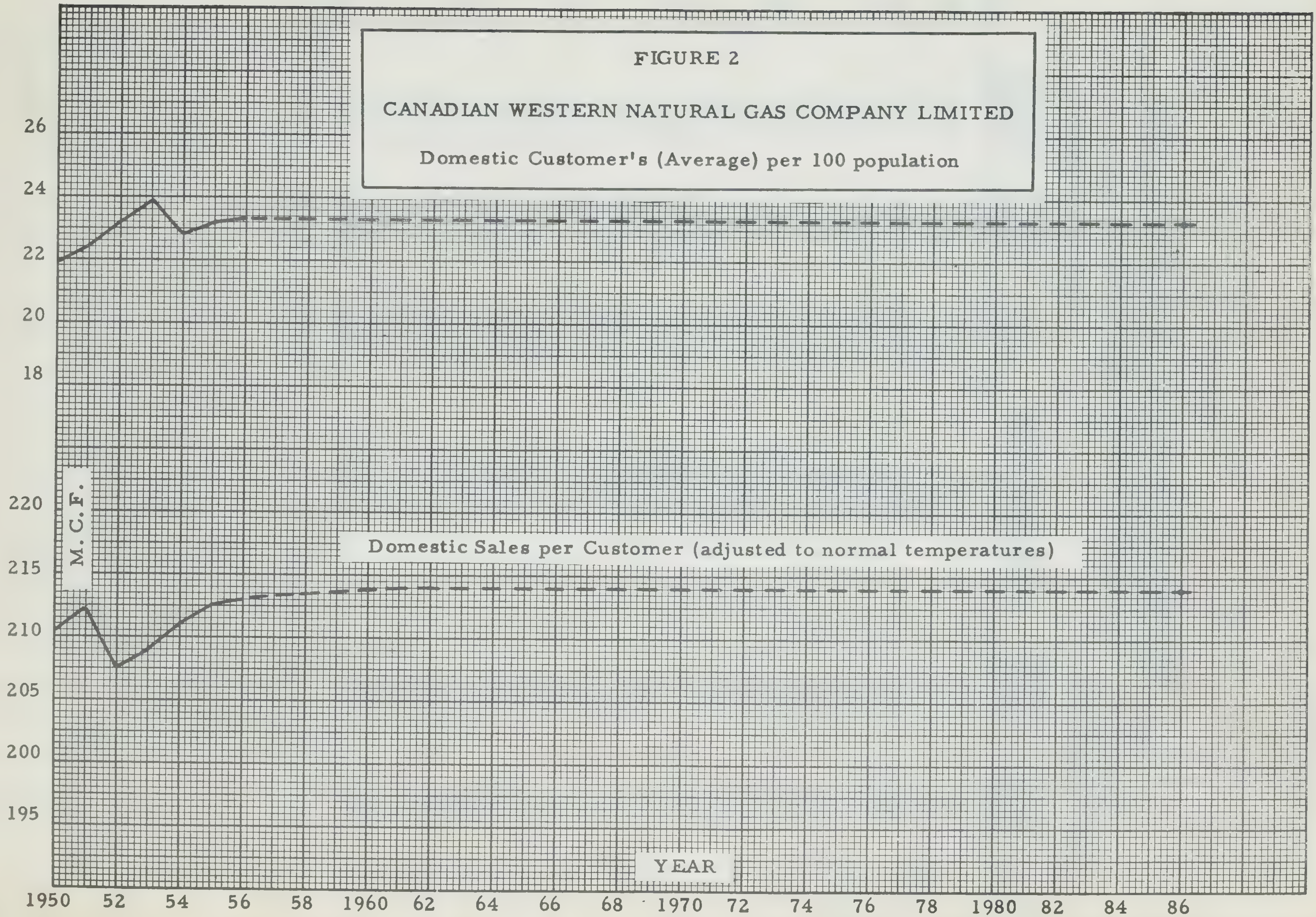


FIGURE 2
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
Domestic Customer's (Average) per 100 population
26
24
22
20
18
M. C. F.
220
215
210
205
200
195
Domestic Sales per Customer (adjusted to normal temperatures)
YEAR
1950
52
54
56
58
1960
62
64
66
68
1970
72
74
76
78
1980
82
84
86

SUMMARY

30 Year Projection of the Annual Market Requirements and
Peak Day Requirements of Canadian Western Natural Gas Company Limited
and Northwestern Utilities, Limited

	Annual Requirements				Year End Peak Day Requirements		
Year	Canadian Western MMMCF	North-western MMMCF	Total MMMCF	Cumulative Total Annual Requirements MMMCF	Canadian Western MMCF/D	North-western MMCF/D	Total MMCF/D
1957	36.2	47.6	83.8	83.8	243	317	560
58	38.4	50.6	89.0	172.8	258	341	599
59	40.7	55.0	95.7	260.5	274	372	646
1960	45.5	60.0	105.5	374.0	300	398	698
61	48.1	64.8	112.9	486.9	316	424	740
62	50.7	69.8	120.5	607.4	331	451	782
63	53.3	74.0	127.3	734.7	347	471	818
64	55.9	78.6	134.5	869.2	363	496	859
1965	58.4	83.2	141.6	1010.8	379	522	901
66	61.0	87.9	148.9	1159.7	394	546	940
67	63.5	92.5	156.0	1315.7	410	572	982
68	66.1	97.1	163.2	1478.9	426	595	1021
69	68.7	101.6	170.3	1649.2	442	615	1057
1970	71.3	105.1	176.4	1825.6	457	637	1094
71	73.8	108.8	182.6	2008.2	473	657	1130
72	76.4	112.4	188.8	2197.0	489	678	1167
73	79.0	115.8	194.8	2391.8	505	699	1204
74	81.5	119.3	200.8	2592.6	521	720	1241
1975	84.1	122.8	206.9	2799.5	536	736	1272
76	86.7	125.8	212.5	3012.0	553	755	1308
77	89.3	128.9	218.2	3230.2	568	775	1343
78	91.8	132.0	223.8	3454.0	584	794	1378
79	94.4	135.0	229.4	3683.4	599	813	1412
1980	96.9	138.0	234.9	3918.3	615	832	1447
81	99.5	141.1	240.6	4158.9	631	847	1478
82	102.1	144.0	246.1	4405.0	647	866	1513
83	104.6	146.9	251.5	4656.5	662	884	1546
84	107.2	150.0	257.2	4913.7	679	904	1583
85	109.8	152.9	262.7	5176.4	694	922	1616
1986	112.4	156.0	268.4	5444.8	710	941	1651
30-Year Totals	2247.3	3197.5	5444.8				

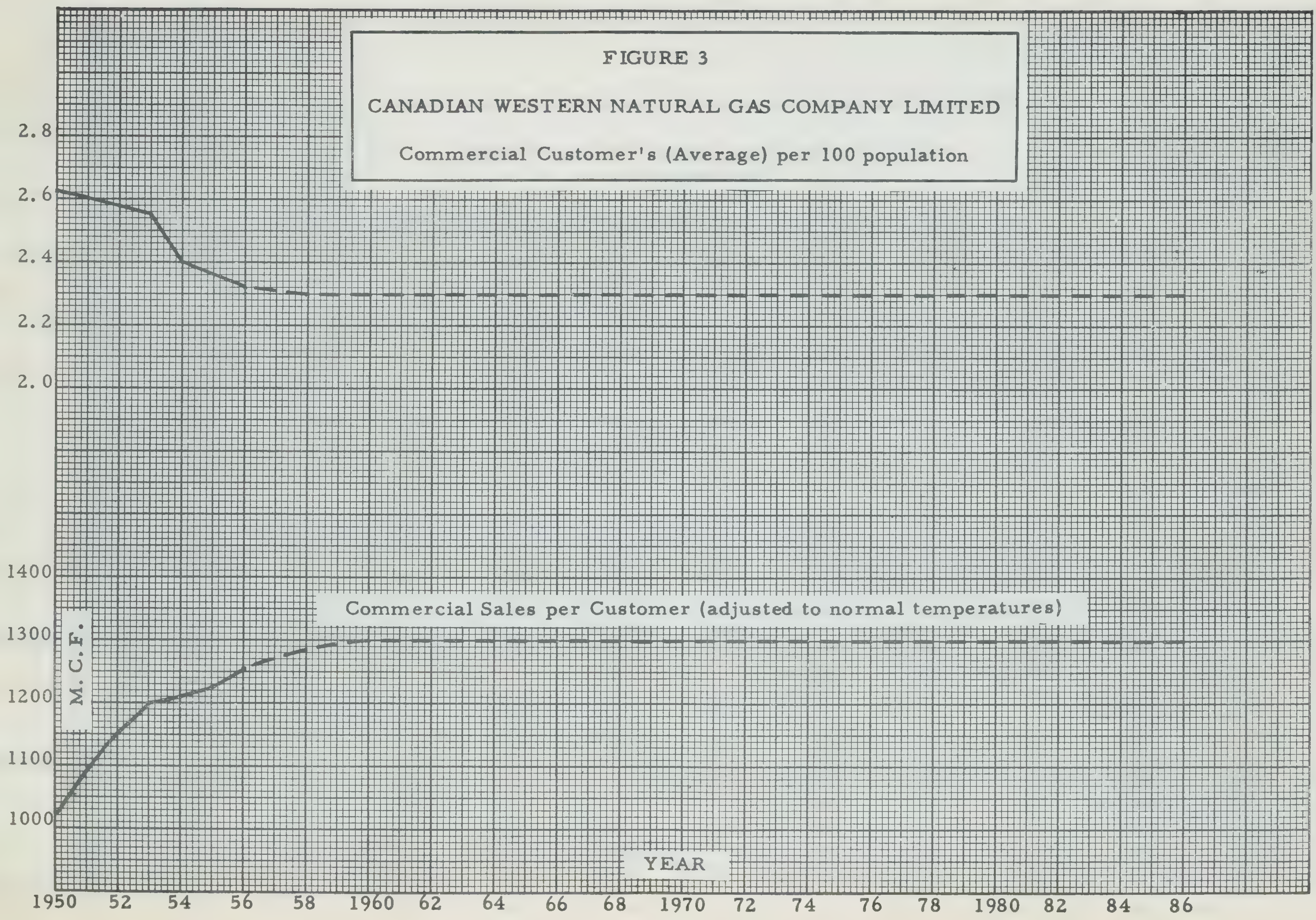


FIGURE 3
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
Commercial Customer's (Average) per 100 population
Commercial Sales per Customer (adjusted to normal temperatures)
M. C. F.
YEAR
2.8
2.6
2.4
2.2
2.0
1400
1300
1200
1100
1000
1950
52
54
56
58
1960
62
64
66
68
1970
72
74
76
78
1980
82
84
86

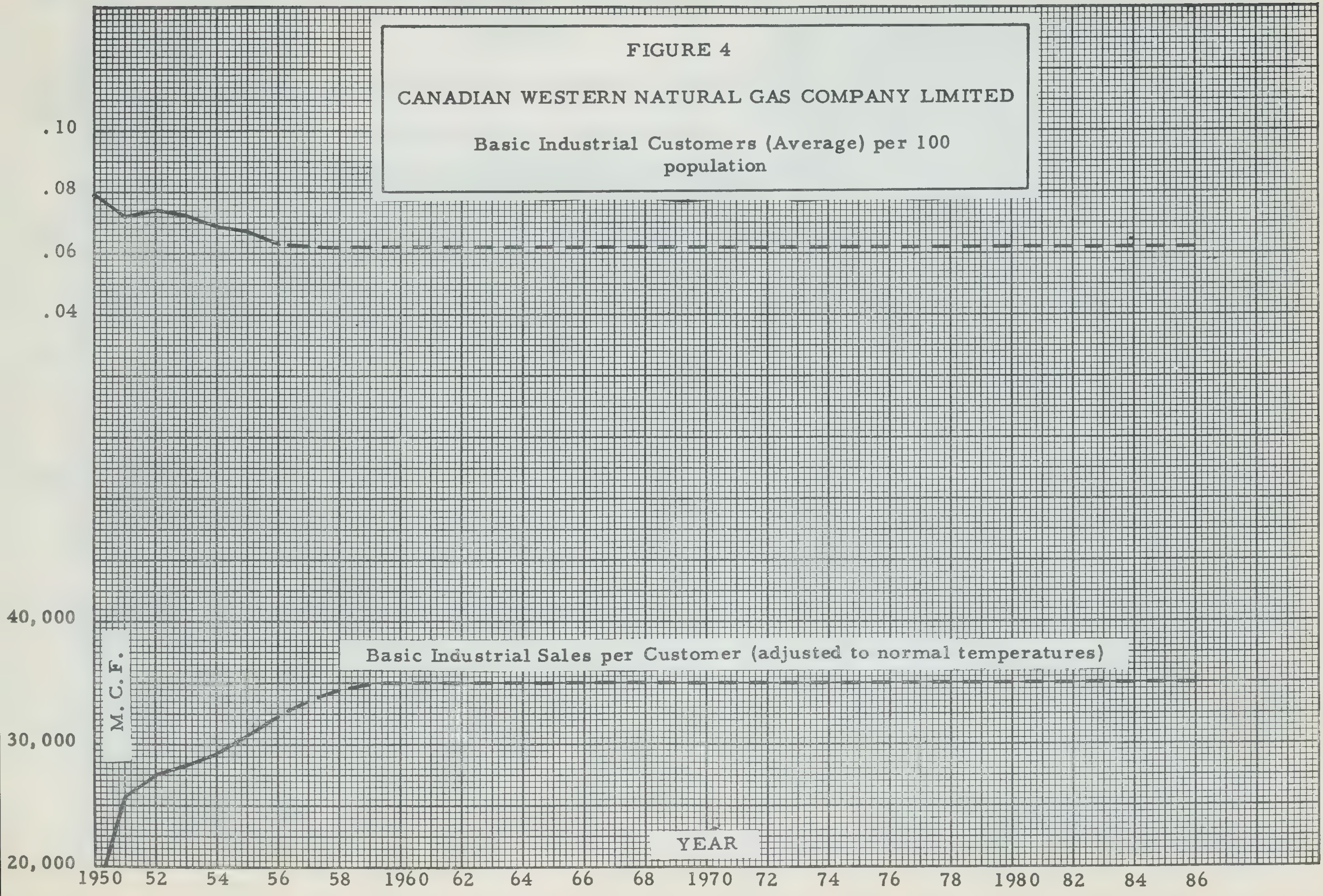


FIGURE 4
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
Basic Industrial Customers (Average) per 100 population
Basic Industrial Sales per Customer (adjusted to normal temperatures)
M. C. F.
YEAR
.10
.08
.06
.04
40,000
30,000
20,000
1950
52
54
56
58
1960
62
64
66
68
1970
72
74
76
78
1980
82
84
86

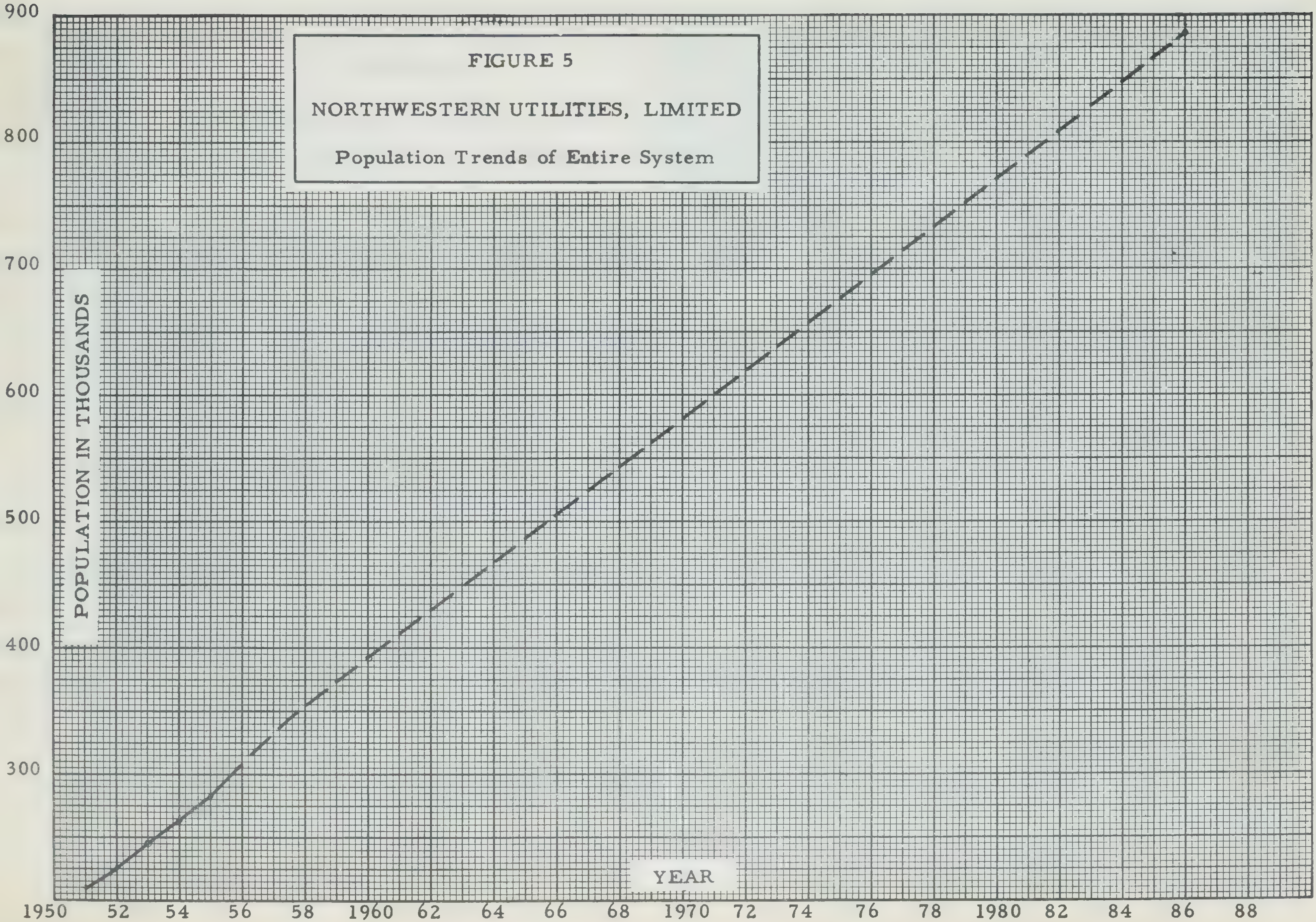


FIGURE 5

NORTHWESTERN UTILITIES, LIMITED

Population Trends of Entire System

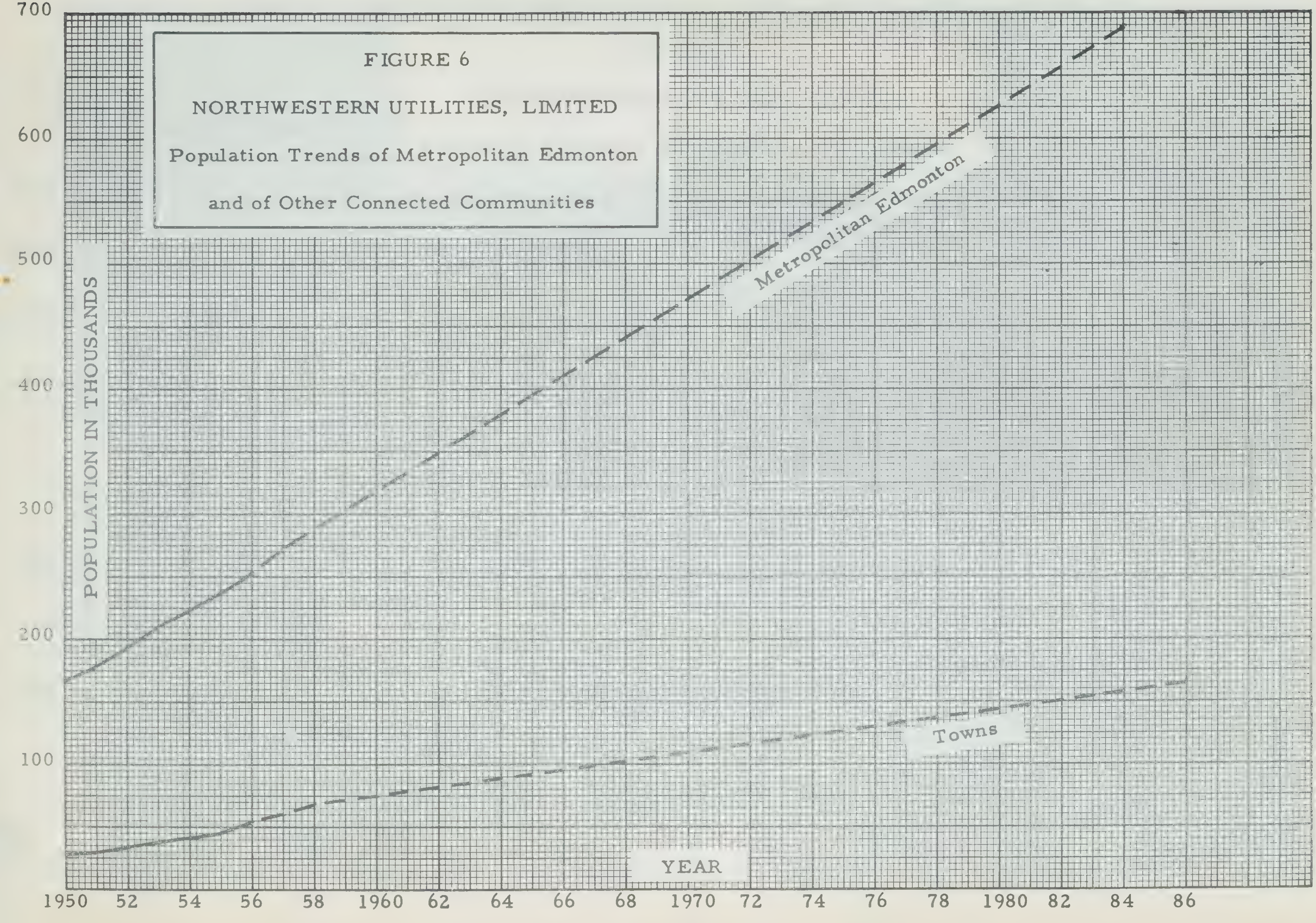


FIGURE 6
NORTHWESTERN UTILITIES, LIMITED
Population Trends of Metropolitan Edmonton
and of Other Connected Communities
POPULATION IN THOUSANDS
700
600
500
400
300
200
100
Metropolitan Edmonton
Towns
YEAR
1950
52
54
56
58
1960
62
64
66
68
1970
72
74
76
78
1980
82
84
86

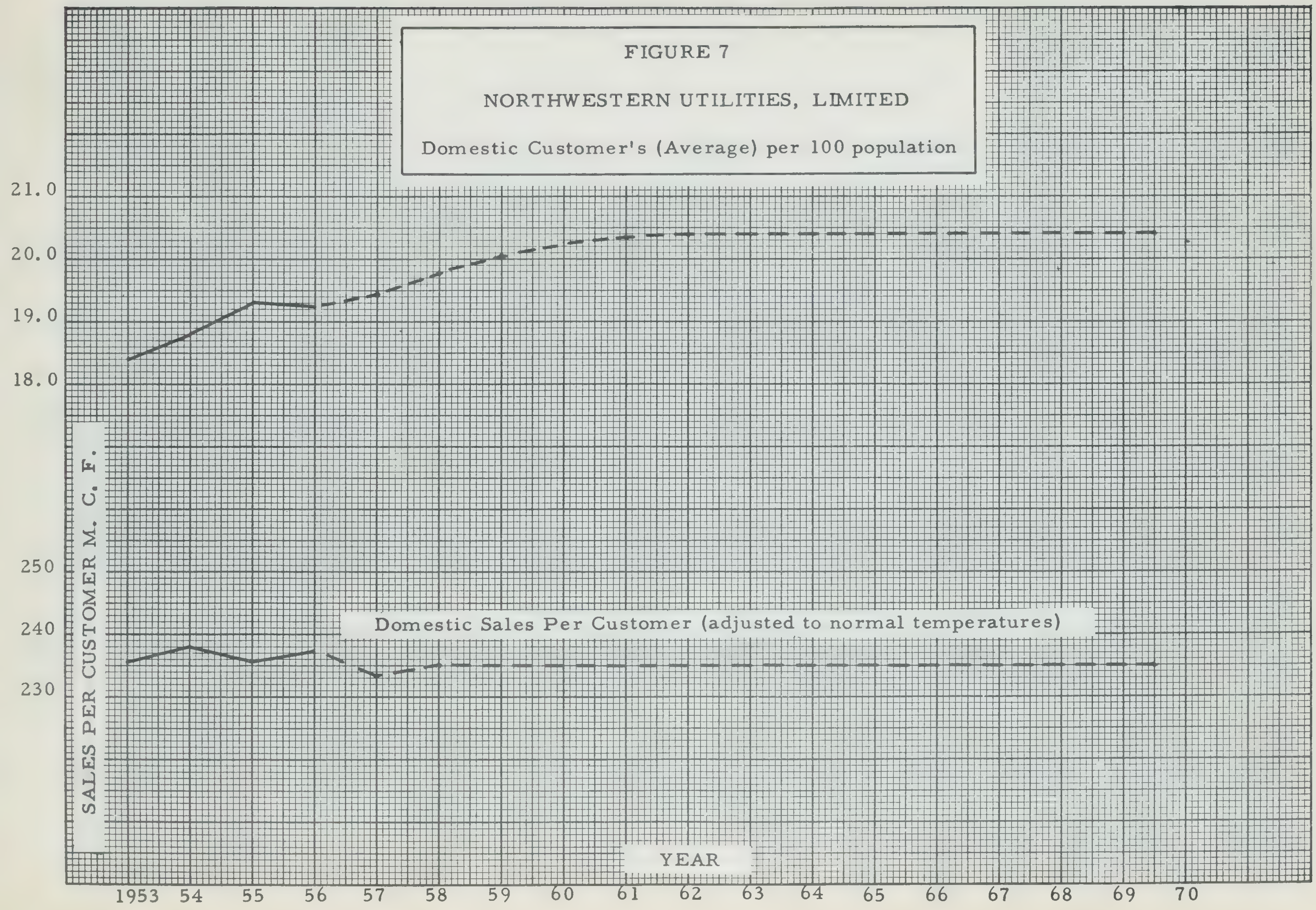


FIGURE 7
NORTHWESTERN UTILITIES, LIMITED
Domestic Customer's (Average) per 100 population
21.0
20.0
19.0
18.0
SALES PER CUSTOMER M. C. F.
250
240
230
Domestic Sales Per Customer (adjusted to normal temperatures)
YEAR
1953
54
55
56
57
58
59
60
61
62
63
64
65
66
67
68
69
70

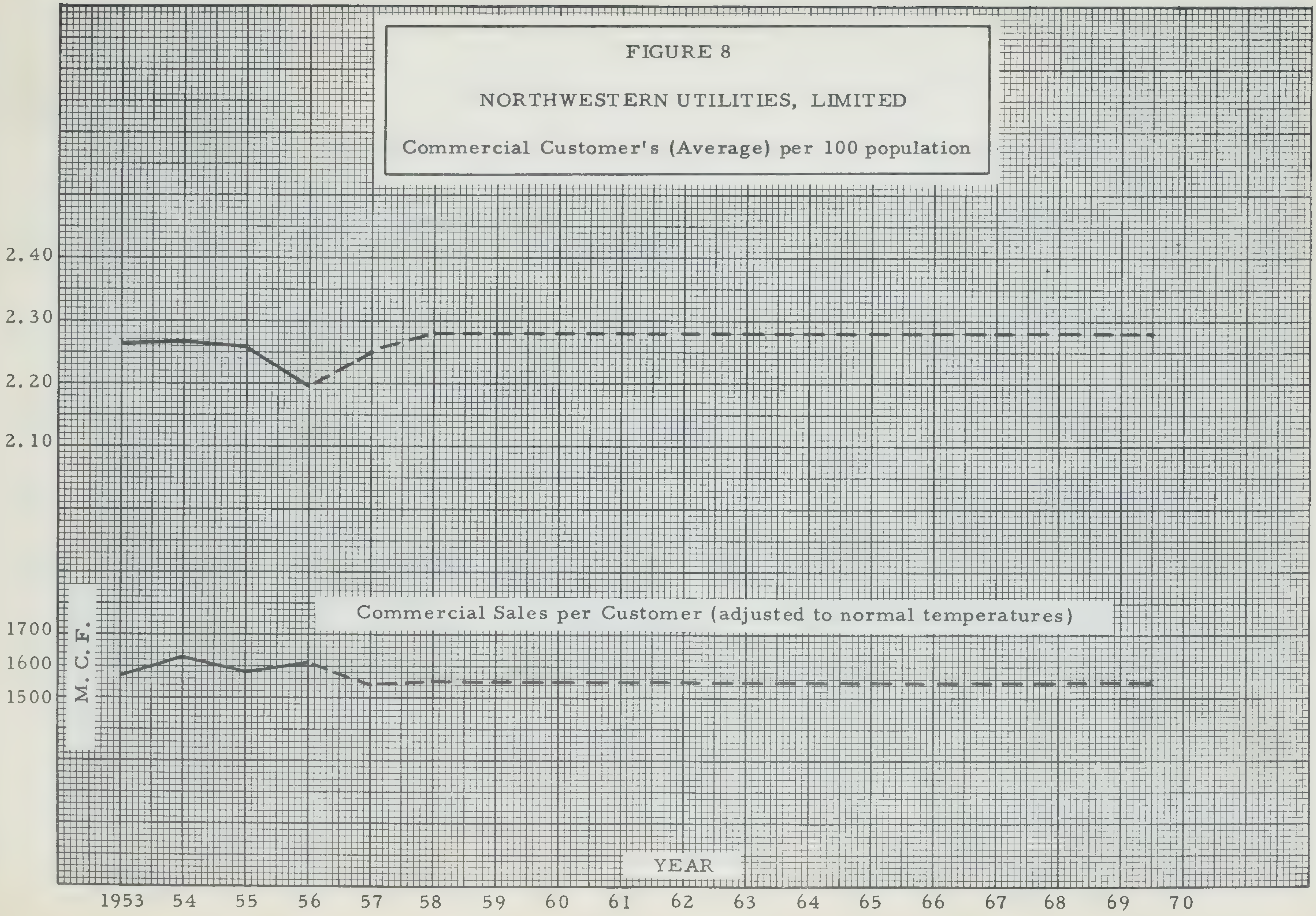
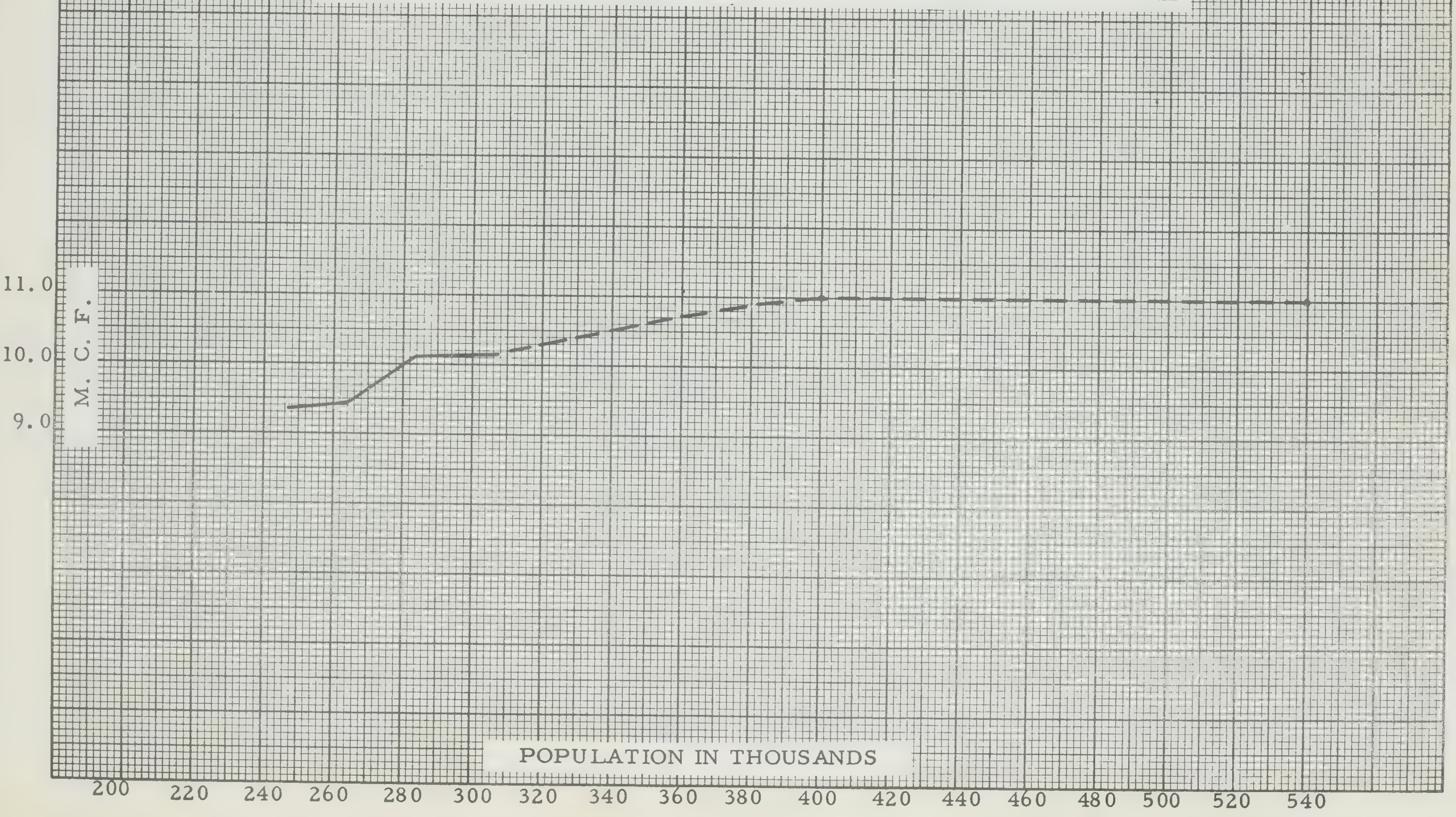


FIGURE 8
NORTHWESTERN UTILITIES, LIMITED
Commercial Customer's (Average) per 100 population
2.40
2.30
2.20
2.10
Commercial Sales per Customer (adjusted to normal temperatures)
M. C. F.
1700
1600
1500
YEAR
1953
54
55
56
57
58
59
60
61
62
63
64
65
66
67
68
69
70

FIGURE 9

NORTHWESTERN UTILITIES, LIMITED

Basic Industrial Sales Per Capita (Adjusted to Normal Temperatures



CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
NORTHWESTERN UTILITIES, LIMITED

BREAKDOWN OF THE TOTAL GAS RESERVES OF ALBERTA INTO DIFFERENT TYPES OF GAS

(Based on Disposable Gas Reserve Estimates Published by the Oil and Gas Conservation Board in a Report of January 31,1957)

Total Reserves Reported by the Board	18,328.1 billion cubic feet
Less: Reserves in very small fields which were not listed individually in the report	617.0
Total for fields identified in the report	17,711.1 billion cubic feet

	Reserves Billions of Cubic Feet	Per Cent of Total Reserves for all Fields Identified in Report
Associated Gas		
(a) Solution Gas	2,132.5	12.1%
(b) Gas Cap Gas	3,137.9	17.7%
Total Associated Gas	5,270.4	29.8%
Sour and Condensate Field Gas	5,177.5	29.2%
Dry Sweet Gas	7,263.2	41.0%
	17,711.1	100.0%

Under Co's control sweet gas { without Carbon about 10 %
with " " 15 %

sour gas - about 10 %

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

CLASSIFICATION OF TYPES OF GAS FOUND IN FIELDS WHICH ARE SOURCES OF SUPPLY FOR THE CANADIAN WESTERN NATURAL GAS COMPANY LIMITED SYSTEM

(Based on Available Pipe Line Gas Reserve Estimates Prepared for the Company as of January 1, 1958)

All Quantities Expressed in Billions of Cubic Feet at Standard Conditions of 14.4 psia and 60° F

Present Sources of Supply	Dry Sweet Gas	Sour and Condensate Field Gas	Associated Gas
Turner Valley	-	-	271
Jumping Pound	-	390	-
Bow Island	17	-	-
Foremost	15	-	-
Brooks	7	-	-
Fenn - Big Valley, Stettler	-	-	48
	39	390	319
	(Total Reserves of Present Sources - 748 billion cubic feet)		
Per Cent of Total Reserves	5.2%	52.1%	42.7%
Additional Sources to be Connected Within 18 Months			
Carbon	206	-	-
Okotoks	-	115	-
	245	505	319
	(Total Reserves Including New Sources - 1069 billion cubic feet)		
Per Cent of Total Reserves	22.9%	47.2%	29.9%

NORTHWESTERN UTILITIES, LIMITED

CLASSIFICATION OF TYPES OF GAS FOUND IN FIELDS PRESENTLY SUPPLYING THE NORTHWESTERN UTILITIES, LIMITED SYSTEM

(Based on the Company's Estimates of Available Pipe Line Gas Reserves as of January 1, 1958)

All Quantities Expressed in Billions of Cubic Feet at Standard Conditions of 14.4 psia and 60° F

	Dry Sweet Gas	Sour and Condensate Field Gas	Associated Gas
Present Sources			
Viking-Kinsella	379	-	-
Leduc-Woodbend	-	-	633
Bonnie Glen -Wizard Lake	-	-	755
Fort Saskatchewan	53	-	-
Fairydell - Bon Accord	96	-	-
Acheson	6	-	54
Samson	-	-	11
Fenn - Big Valley, Stettler	-	-	29
Beaverhill Lake	139	-	-
Wildmere	4	-	-
	677	-	1482

(Total Reserves of Present Sources - 2159 billion cubic feet)

Per Cent of Total	31.4%	-	68.6%

Note: Reserves of certain associated gases with high heating values have been converted to 1000 BTU's per cubic foot basis.

NORTHWESTERN UTILITIES, LIMITED

Economics of Production from the Viking-Kinsella Field

The largest gas field owned by the Companies is Northwestern's Viking-Kinsella Field. This field was discovered in 1914 but was not connected to a market until 1923. Development has taken place continuously from that time until the present. Northwestern Utilities owns or controls the greater part of this field -- approximately 469 square miles, and there are 88* wells tied into the gathering system, an average of one well per 5.3 square miles. The production formation is a relatively thin sand in the Viking Formation, of Lower Cretaceous age, found at a depth averaging 2,000 feet. The field is of relatively good porosity and 10-day stabilized open flows of the wells average 5.2 million cubic feet per day, ranging up to 11 million. Reserves owned or controlled by the Companies as at January 1st 1958 total 378 billion cubic feet with an average shut-in pressure in October 1957 of 540 psig. The gas is sweet, contains negligible amounts of condensate hydrocarbons and requires only dehydration before delivery to market.

The total investment in the field as at December 31st 1956 was as follows:

Gas Wells	$1,913,680
Leaseholds and Gas Rights	3,182,987
Gathering System, including dehydration, metering and regulating equipment	3,427,525
Structures	413,008
Miscellaneous	105,463
	$9,420,663

* Excludes 4 wells in south-east corner of field producing from a lower formation.

The investment, both for acquisition of leases and gas rights and for physical plant would be very substantially higher at present day cost levels.

An indication of the approximate producing cost per Mcf is given by the following:

<u>Assumptions re Fixed Charges</u>

Return -- 7.5% on total investment, ignoring accrued depreciation

(Note: It is obvious that the Company's overall allowable rate of return of 7.5% is not appropriate to the higher risk production part of its operations. Since there is no established precedent governing this, accrued depreciation has been ignored as some offset to a more appropriate higher rate of return)

Annual Depreciation	--	3.0%
Income Taxes	--	2.5% (Consistent with 1956 actual experience for the system reflecting depletion allowance and drilling credits)

<u>Annual Costs - 1956</u>

Total Fixed Charges	-- 13.0% on $9,042,663 =	$1,175,546
Operation and Maintenance Expense (Calculated share of total system production expense)		583,646
Total Annual Costs, exclusive of administration and overhead expense		$1,759,192

∴ Production cost per Mcf = 8.97¢

Effect of Load Factor

The calculated maximum deliverability of the field at the end of 1956 was 150 million cubic feet. Average daily production during the year was 53.7 million cubic feet. Hence, the field operated at 36% load factor. If production had been taken at higher load factor, unit cost would have been much lower since the only significant increase in cost would have been royalties. For example, at 50% load factor, unit production cost would have been 6.6¢ per Mcf and at 75% load factor, 4.6¢ per Mcf. On the other hand, if the field had been operated solely for peaking purposes with an annual production of, say, 2,000,000 Mcf, unit costs would have been 82.7¢ per Mcf. This figure in a relatively low cost field such as this gives some measure of the extremely high cost which would be associated with peak load gas if this were developed from condensate fields or oil fields where expensive processing facilities would be required.

STANFORD RESEARCH INSTITUTE

MENLO PARK, CALIFORNIA

August 1957

DEMAND FOR NATURAL GAS AND ITS IMPACT ON INDUSTRIAL GROWTH IN ALBERTA 1957-1970

S R I Project No. I-2256

Prepared for:

NORTHWESTERN UTILITIES, LIMITED EDMONTON, ALBERTA
CANADIAN WESTERN NATURAL GAS COMPANY LIMITED CALGARY, ALBERTA

Approved:

Charles L. Hamman

CHARLES L. HAMMAN, ASSISTANT DIRECTOR OF ECONOMICS RESEARCH

Paul J. Lovewell

PAUL J. LOVEWELL, DIRECTOR OF ECONOMICS RESEARCH

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Section I

INTRODUCTION

Northwestern Utilities, Limited and Canadian Western Natural Gas Company Limited[1/] distribute gas to domestic, commercial, and industrial customers in Edmonton, Calgary, and 68 other communities in central and southern Alberta.

At the present time the greater part of Alberta's energy requirements, exclusive of transportation uses, are supplied by natural gas. In the future, however, alternative energy sources such as coal, heavy fuel oil, and other fuels will play a more important role in supplying energy requirements, particularly to industrial consumers. This may come about because of higher natural gas prices caused by greater competition for gas supplies and the higher cost of additional facilities for producing, gathering, and distributing increased quantities of gas to meet the expected demand.

In June 1957, Canadian Western and Northwestern Utilities engaged Stanford Research Institute to make an analysis of Alberta's future energy requirements with the following objectives:

1. To determine the future energy requirements, exclusive of transportation uses, of the Province of Alberta and to determine which fuels will probably supply these requirements.

2. To review the effect of low-cost natural gas on industrial growth in Alberta

A review and analysis of available statistics on fuel consumption in Alberta was made for the period 1949 to 1956. Based on this analysis, an estimate of the energy consumption in the province by source of energy and by end use--domestic, commercial, and industrial--was compiled. Forecasts of the energy requirements of the province by end use were made for 1960, 1965, and 1970. These forecasts were based on projections of per capita energy requirements and a forecast of Alberta's population

---

1/ Hereafter referred to as Northwestern Utilities and Canadian Western, respectively.

The sources of energy expected to supply the above-mentioned forecast of energy requirements were then estimated, based upon:

1. An analysis and forecast of the availability and prices of coal, fuel oils, and liquefied petroleum gases in Alberta. Information for this analysis was obtained from the railroads and several associations and government agencies, including the Research Council of Alberta, the Coal Operators Association of Western Canada, the Alberta LP Gas Association, and the Alberta Power Commission.

2. A survey of 39 large industrial and commercial fuel consumers in the province to determine their views toward the use of various fuels.

The assessment of the importance of low-cost natural gas to the industrial growth of the province was based upon the above-mentioned survey of industrial fuel consumers and an analysis of similar studies conducted in the United States.

The general economic framework includes the assumptions that overall economic activity in the province will remain at a high level during the period under consideration and that no major changes in technology will occur to alter present energy consumption patterns.

The study was conducted in the Division of Economics Research of Stanford Research Institute by John W. Gouge and H. Gordon Pearce, assisted by Richard H. Raymond. The project was under the administrative direction of Carl A. Trexel, Jr.

The Institute wishes to express its appreciation for the cooperation and assistance received from the staff of Northwestern Utilities and Canadian Western and from the many other organizations and individuals throughout the province contacted during the course of the study.

Section II

SUMMARY AND CONCLUSIONS

1. By 1970, Alberta's total energy requirements, exclusive of transportation uses, will increase to 329 Bcf,[1/] an increase of 124 percent of the 1956 requirements of 147 Bcf. Total consumption of natural gas during this period is expected to increase by 109 percent, from 106 Bcf in 1956 to 222 Bcf in 1970.

X

2. Natural gas will probably continue to supply the major part of urban domestic and commercial energy requirements during the forecast period, 1957 to 1970. During this period, however, it is expected that the percentage of total industrial energy requirements provided by natural gas will decrease from 75 percent in 1956 to 62 percent in 1970. This reduction is the result of the anticipated loss of certain industrial markets currently served by natural gas.

It is expected that the dieselization program of the railroads will be near completion by 1960. As a result of this program, there will be a potential surplus of about 3,000,000 barrels of heavy fuel oil in Alberta. To aid in disposing of this potential surplus, the oil companies can use the heavy fuel oil in place of natural gas currently used if price of fuel oil reflects its surplus market position. Additional market outlets will also need to be found. The consumption of natural gas by the oil refineries in Alberta is currently about 15 percent of total industrial natural gas consumption

At present most of the thermal electric stations in Alberta are gas fired. The additional thermal electric capacity to be installed prior to 1960 is also expected to be gas fired. However, after 1960 it is expected that the majority of new thermal electric generating capacity will be coal fired and that some existing gas-fired stations will convert to coal.

In 1956 about 88 percent of the fuel requirements of Alberta thermal electric stations was supplied by natural gas, but by 1970 it is expected that natural gas will provide only about 39 percent of the thermal electric stations' requirements. The balance will be supplied largely by coal.

1/ Billions of cubic feet natural gas equivalent.

3. Low-cost natural gas will not be a major factor in the continued industrial growth of Alberta. In July 1957, a field survey was made, by Stanford Research Institute, of the industrial consumers using 85 percent of the total industrial natural gas consumption in Alberta in 1956. This survey showed that none of Alberta's new industries had located in the province specifically because of the availability of low-cost natural gas as fuel. Two possible exceptions were the ammonia plants and the polyethylene plant which use the natural gas as a raw material. The results of this survey in Alberta are substantiated by other studies conducted in similar areas which indicate that the most important plant location factors in order of declining importance are markets, labor, raw materials, and transportation.

Future industrial expansion in Alberta will include: (1) expansion of primary industries to utilize raw materials such as crude oil, coal, timber resources, and water; for example, construction of a butadiene plant at Red Deer using butane as a raw material has been announced by the Polymer Corporation; and (2) expansion of secondary industries locating in Alberta because of the growing importance of Prairie markets. Both types of industries will be potential consumers of natural gas for fuel requirements but their decisions to locate in Alberta will not be based primarily on the cost of natural gas as a fuel.

Section III

TOTAL ENERGY REQUIREMENTS IN ALBERTA

Alberta's total energy requirements, exclusive of transportation uses, are shown in Figure 1. The historical section of this graph, 1949-1956, is based upon statistics and estimates of the consumption of various sources of energy by end use--domestic, commercial, or industrial.[1/] The fuels or sources of energy included in the total energy balance are natural gas, coal, fuel oils, LPG and refinery gases, and hydroelectric power. The heat values and burning efficiencies used in converting these fuels to a common equivalent basis are shown in Appendix A.

The forecast of energy requirements by end use to 1970 is based upon a modified projection of per capita energy demand by end use and a forecast of Alberta's population. A detailed description of the method used in forecasting energy requirements by end use is shown in Appendix B.

As shown in Figure 1, Alberta's total energy requirements increased from 79 Bcf[2/] in 1949 to 147 Bcf in 1956, an increase of 86 percent. By 1970 it is expected that total energy requirements will be 329 Bcf, an increase of 124 percent over 1956.

The percentage distribution of energy requirements by end use as shown in Appendix C indicates that the growth of industrial energy requirements is considerably greater than the growth of domestic or commercial requirements. In 1949 industrial requirements were 47 percent of the total. By 1956 this percentage had increased to 51 percent, and by 1970 it is expected to increase further to 55 percent. This increase in the industrial percentage of total energy requirements is a reflection of the rapid industrial growth in the province.

Total energy requirements of Alberta for selected years are shown by source of energy in Figure 2. As noted from this figure and Appendix D,

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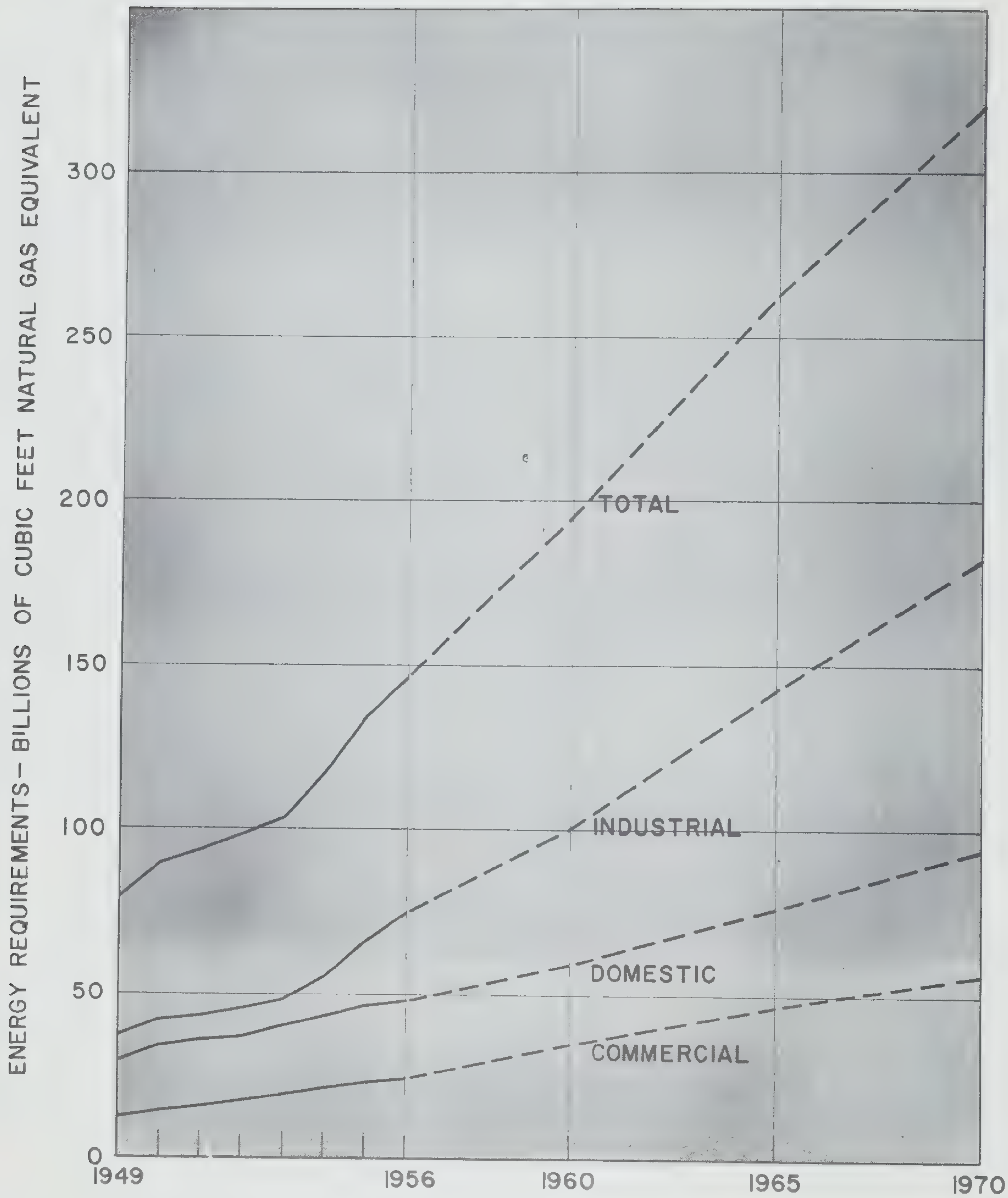
1/ Definition of terms: domestic - residential use, both urban and rural; commercial - use by commercial establishments, such as stores, hotels, etc.; industrial - use by industrial firms, such as oil refineries, cement plants, thermal electric stations, etc.

2/ Billions of cubic feet natural gas equivalent.

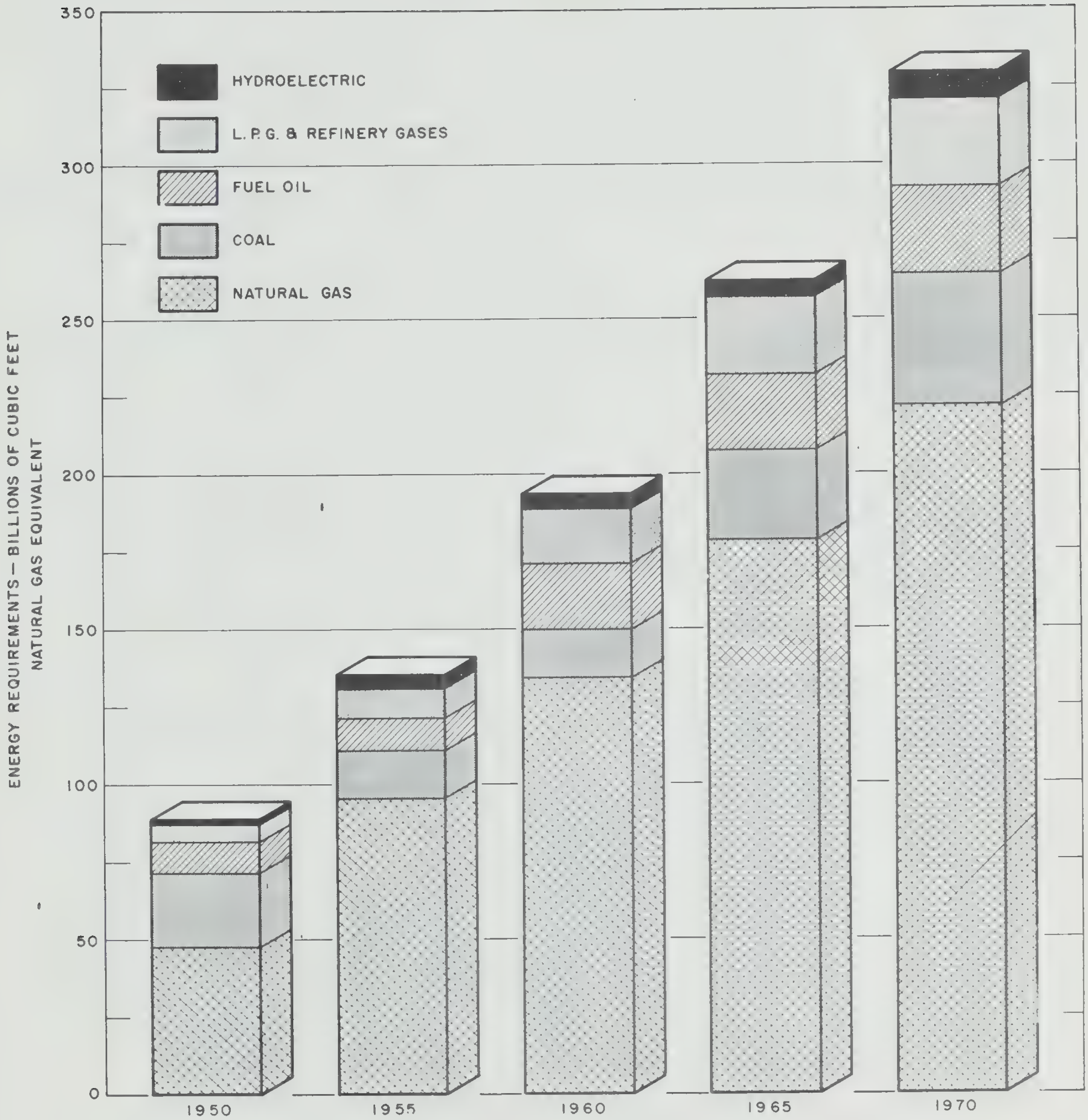


SOURCES: 1949 – 1956 — Dominion Bureau of Statistics.
Alberta Bureau of Statistics.
Petroleum and Natural Gas Conservation Board, Province of Alberta.
Alberta Power Commission.

1957 – 1970 — Estimates by Stanford Research Institute.

FIG. 1

TOTAL ENERGY REQUIREMENTS IN ALBERTA BY END USE
(Exclusive of Transportation Requirements) 1949-1970



SOURCES: 1950 AND 1955 — Dominion Bureau of Statistics.
Alberta Bureau of Statistics.
Petroleum and Natural Gas Conservation Board, Province of Alberta.
Alberta Power Commission.

1960, 1965, and 1970 — Estimates by Stanford Research Institute.

FIG. 2

TOTAL ENERGY REQUIREMENTS IN ALBERTA BY SOURCE
(Exclusive of Transportation Requirements) 1950-1970

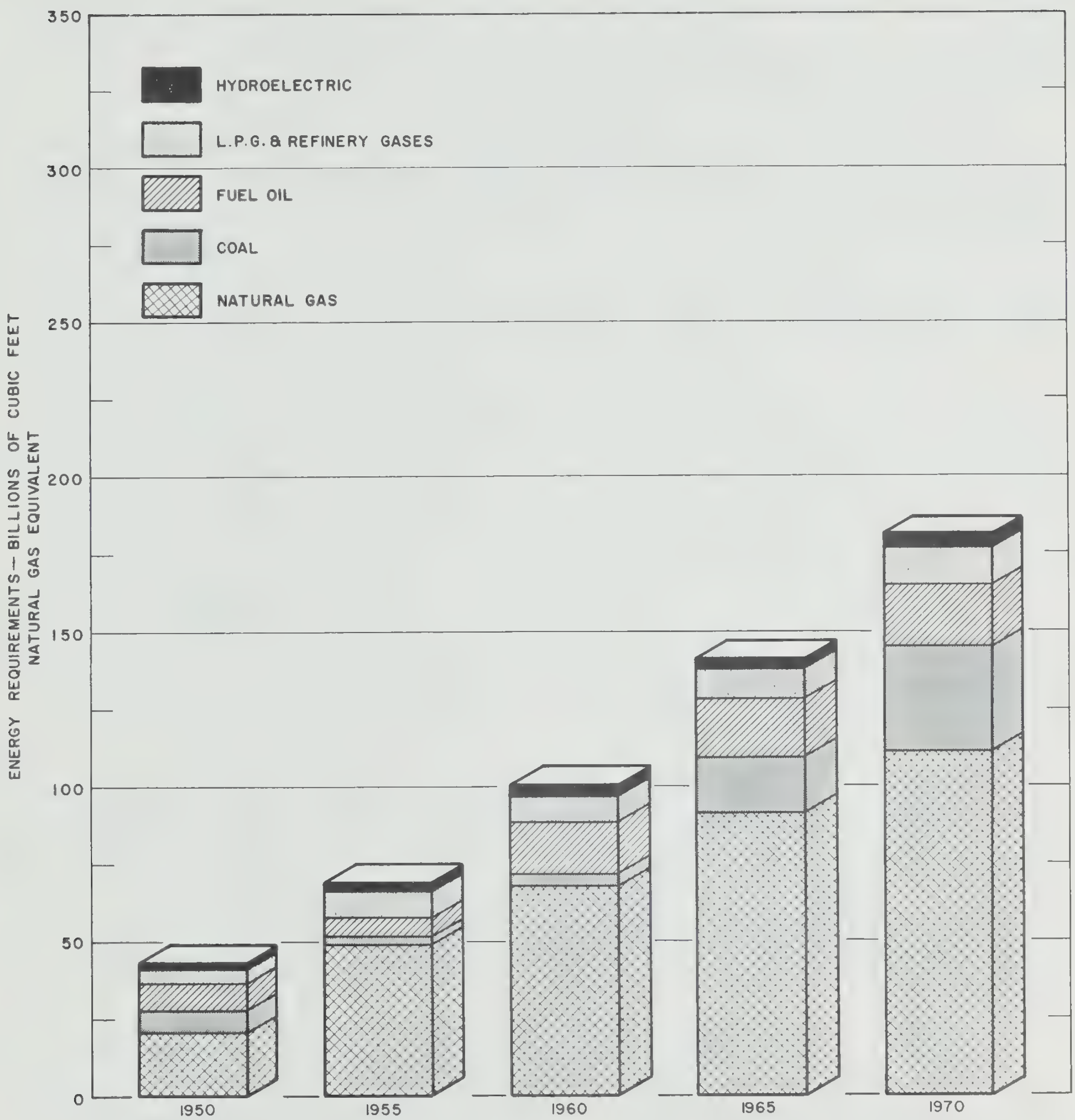
the percentage of total energy requirements supplied by natural gas increased from 54 percent in 1950 to 71 percent in 1955. However, by 1970 the percentage of total energy supplied by natural gas will have decreased to 68 percent, which is the result of an expected decrease in the percentage of total industrial energy supplied by natural gas. The percentage of total domestic energy requirements provided by natural gas will increase from 63 percent to 68 percent between 1956 and 1970, as shown in Appendix E. During this period the percentage of total commercial energy requirements provided by natural gas will remain constant (see Appendix F).

The percentage of total industrial energy requirements provided by natural gas as shown in Figure 3 and Appendix G will drop from 73 percent in 1955 to 62 percent in 1970. This decrease will result from the loss of industrial natural gas markets to coal and heavy fuel oil.

In 1956, Alberta oil refinery use of natural gas was about 15 percent of total industrial gas consumption. By 1960, natural gas in this use will be displaced by heavy fuel oil because of the expected surplus position of heavy fuel oil in the province resulting from the dieselization program of the railroads. This heavy fuel oil situation is described in more detail in Section IV.

At the present time nearly all the thermal electric stations in the province are gas fired. Until 1960, new thermal electric stations are also expected to be gas fired. However, after 1960 most new thermal electric stations will be coal fired and some of the existing gas-fired stations will probably convert to coal. These developments will result from coal being available to thermal electric stations in many areas at less cost than natural gas. In 1956, the fuel requirements, chiefly natural gas, of thermal electric stations were about 23 percent of total provincial industrial fuel requirements. By 1970, fuel requirements of thermal electric stations will be about 31 percent of total industrial energy requirements and more than half of the fuel requirements of these stations will be supplied by coal.

Although it is forecast that between 1956 and 1970 the percentage of total provincial energy requirements provided by natural gas will decrease, a large increase in provincial gas requirements is still anticipated. Between 1949 and 1956, total gas consumption in Alberta increased from 42 Bcf to 106 Bcf, an increase of 152 percent. By 1970, natural gas requirements of the province will have increased to 222 Bcf, an increase of 109 percent over 1956.



SOURCES: 1950 AND 1955 – Dominion Bureau of Statistics.
Alberta Bureau of Statistics.
Petroleum and Natural Gas Conservation Board, Province of Alberta.
Alberta Power Commission.

1960, 1965, and 1970 – Estimates by Stanford Research Institute.

FIG. 3

INDUSTRIAL ENERGY REQUIREMENTS IN ALBERTA BY SOURCE
(Exclusive of Transportation Requirements) 1950-1970

Industrial natural gas consumption increased from 16 Bcf in 1949 to 56 Bcf in 1956, an increase of 243 percent. In spite of the anticipated loss of some industrial natural gas markets as outlined above, by 1970 industrial natural gas requirements will have increased to 112 Bcf, an increase of 100 percent over 1956.

In determining total future energy requirements in Alberta, an estimate of provincial natural gas requirements was made. For information purposes, comparisons of Stanford Research Institute's forecasts of Alberta's natural gas requirements and similar forecasts prepared by the Alberta Petroleum and Natural Gas Conservation Board and Canadian Western and Northwestern Utilities, are shown in Tables I and II.

Table I gives a comparison of estimates made by Stanford Research Institute and the Petroleum and Natural Gas Conservation Board of the demand for natural gas in Alberta by end use for the years 1960, 1965, and 1970. As shown in the table, both forecasts of domestic and commercial natural gas requirements are similar for 1960 and 1965. In 1970, the Stanford Research Institute forecast is somewhat higher than that of the Conservation Board. This difference is largely due to the fact that both forecasts are based on estimates of per capita demand and the population of Alberta and that the population forecast used by Stanford Research Institute for 1970 is somewhat higher than that used by the Conservation Board (see Appendix B).

The wide difference in the forecasts of Alberta's industrial natural gas requirements shown in Table I is due to the Institute's conclusion that in the future the oil refinery and part of the thermal electric station natural gas markets will be lost to competitive fuels. The difference in the forecasts of total provincial natural gas requirements is largely due to the difference in the forecasts of industrial natural gas requirements.

Table II gives a comparison of the forecast made by Stanford Research Institute and the combined forecast of Canadian Western and Northwestern Utilities of the natural gas requirements in those areas served by these two utility companies.

This table indicates that the two forecasts of domestic and commercial natural gas requirements for the years 1960 and 1965 are similar but that in 1970 the Stanford Research Institute forecast is somewhat higher. This difference is due to the fact that both forecasts are based indirectly on estimates of per capita natural gas requirements and population and that the 1970 population estimate of the utility companies is lower than that used by Stanford Research Institute.

Table I

COMPARISON OF CONSERVATION BOARD AND STANFORD RESEARCH
FORECASTS OF ALBERTA NATURAL GAS REQUIREMENTS
(Billions of Cubic Feet Natural Gas)
1956-1970

Forecasts	Actual 1956	Forecasts		
		1960	1965	1970
Total Alberta Gas Requirements	106.5			
Conservation Board		168.1	226.9	257 0
Stanford Research		134.1	178.5	222.0
Alberta Domestic Gas Requirements	30.8			
Conservation Board		38.2	49.5	56.2
Stanford Research		38.4	[illegible]	62.6
Alberta Commercial Gas Requirements	20.1			
Conservation Board		[illegible]	35.2	40.2
Stanford Research		[illegible]	38.2	47.6
Alberta Industrial Gas Requirements	55.6			
Conservation Board		101 9	142.2	160.6
Stanford Research		67.7	90.1	111.8

Table II

COMPARISON OF UTILITY COMPANIES AND STANFORD RESEARCH FORECASTS OF ALBERTA NATURAL GAS REQUIREMENTS[1/]
(Billions Cubic Feet Natural Gas)
1956-1970

Forecasts	Actual 1956	Forecasts		
		1960	1965	1970
Total	79.8			
Utility Companies		106.7	142.8	177.7
Stanford Research		95.6	137.6	172.4
Domestic	27.7			
Utility Companies		34.9	43.2	51.7
Stanford Research		34.9	45.7	57.0
Commercial	19.2			
Utility Companies		24.8	30.4	36.1
Stanford Research		26.6	36.3	45.2
Industrial	32.9			
Utility Companies		47.3	69.1	89.9
Stanford Research		34.1	55.6	70.2

1/ "Utility companies" refers to Canadian Western and Northwestern Utilities.

The reason for the difference in the two forecasts of industrial natural gas requirements is the same as that suggested above; that is, the oil refinery and part of the thermal electric station requirements for energy will be filled by fuel oil and coal rather than natural gas.

The above discussion refers only to natural gas requirements for use in Alberta and does not include possible export requirements.

Section IV

AVAILABILITY AND PRICE OF COMPETITIVE INDUSTRIAL FUELS

Natural gas will have to compete with coal, heavy and light fuel oils, refinery gases, and liquefied petroleum gases in the future. Although hydroelectric power is not strictly a competitive fuel, it has been included to give a complete picture of total energy demand. The following discussion describes the extent to which these various fuels will compete with natural gas in the industrial market.

Coal

Figure 4 illustrates the widespread location of coal reserves within Alberta. These reserves, which include both bituminous and subbituminous coal, are equivalent to about 980 trillion cubic feet of natural gas. The estimate for bituminous coal reserves is based on seams 3 feet or more in thickness to a maximum depth of 2,500 feet. The subbituminous coal reserves are estimated on the basis of seams 3 feet or more in thickness with not more than 1,000 feet of overburden.

Most of the coal reserves are located some distance from Alberta's major industrial areas and consequently are subject to high freight costs. Coal areas which are close to the market areas and which enjoy comparatively low production costs are shown in black on Figure 4. Strip mines in the Pembina and Edmonton coal areas are potentially the lowest cost sources of coal to the Edmonton industrial area. Strip mines in the Castor area are significant as sources of energy for Red Deer and the Battle River power station. Coal from underground mines in the Drumheller area is the lowest cost coal available to the Calgary industrial area. Although fairly high in cost, coal from the Lethbridge coal area is the lowest cost coal available in this industrial area. Crowsnest coals are potential sources of fuel for thermal electric generating stations which may be located in southwestern Alberta. Cascade coals are potential sources of fuel for industry located in that area.

The delivered prices of coal to various industrial centers are shown in Table III, for the years 1957, 1960, 1965, and 1970. The forecasts assume that there will be no increase in the price of coal in terms of constant dollars until after 1960. Between 1960 and 1965 increases of 5-10 percent in coal prices at the mine have been forecast. The 5 percent increase is forecast for strip mines, the 10 percent increase

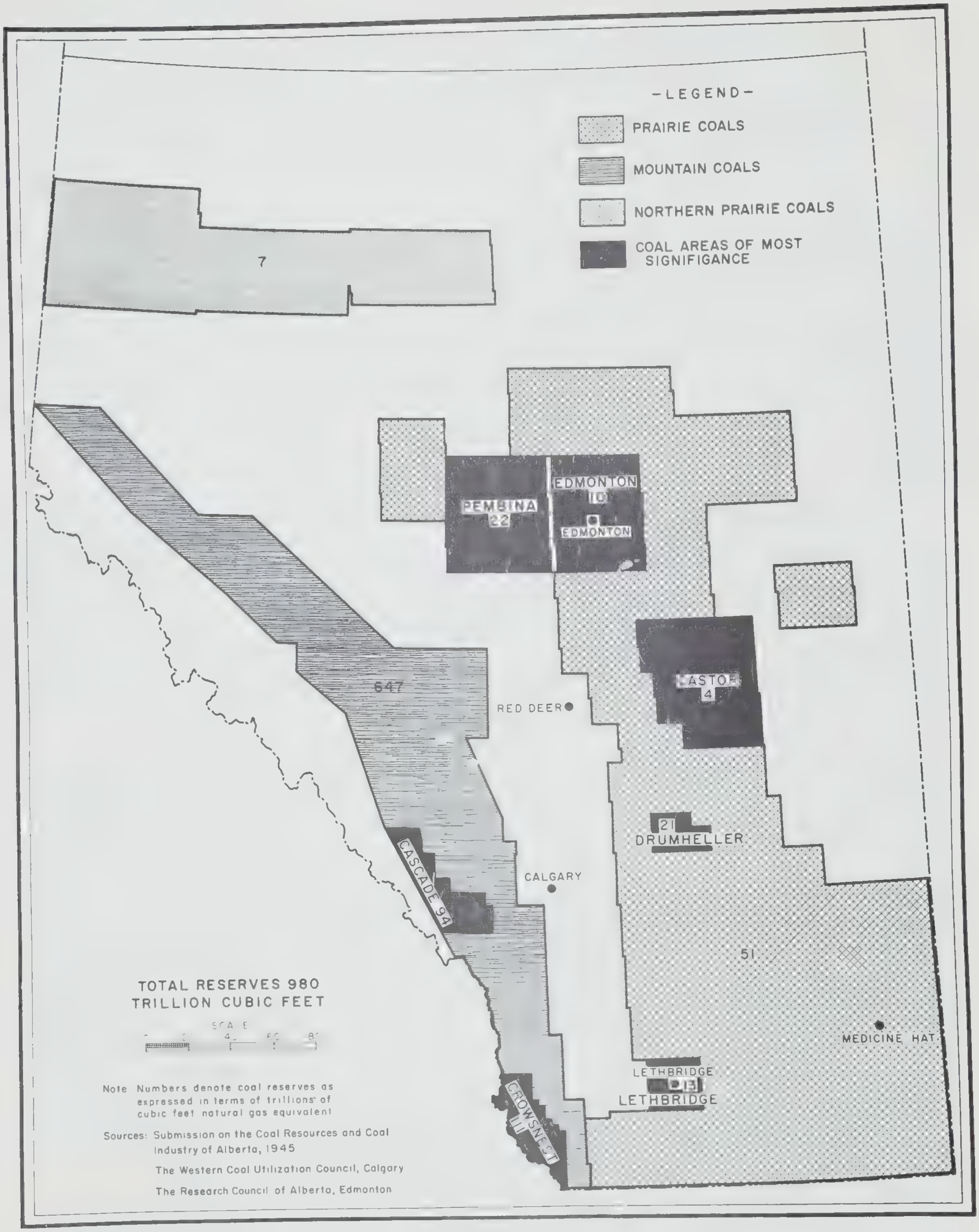


FIG. 4

COAL RESERVES IN ALBERTA

Table III

ESTIMATED PRICES OF COMPETITIVE INDUSTRIAL FUELS
IN ALBERTA IN CONSTANT 1957 DOLLARS
1957, 1960, 1965, and 1970
(In Cents per Mcf Natural Gas Equivalent)

Fuel and Year	Edmonton	Red Deer	Calgary	Lethbridge
Coal				
1957	15-17	19	31	16
1960	15-17	22	31	16
1965	16-18	23	34	17
1970	16-19	25	36	19
Heavy Fuel Oil				
1957	37	48	42	56
1960	37	48	42	56
1965	37	48	42	56
1970	37	48	42	56
Light Fuel Oil				
1957	87	99	97	112
1960	87	99	97	112
1965	93	105	103	119
1970	99	111	110	125

Source: Estimates by Stanford Research Institute, based on conversion factors in Appendix A.

for underground mines. Similar increases are forecast for the period 1965 to 1970. In addition, during each of these periods, 5 percent increases in freight rates in terms of constant dollars have been estimated.

Heavy Fuel Oil

Heavy fuel oil production is dependent upon quantity and quality of the crude oil processed, refinery throughput, and the type of processing facilities at the different refineries. In 1956, total apparent production of heavy fuel oil was 4,700,000 barrels, which represents a yield of about 18 percent of total crude oil throughput. The refineries in Alberta are currently operating for a minimum yield of heavy fuel oil within the limits of existing refining units. Installation of additional coking and catalytic cracking facilities, along with an increase in the production of asphalt, is expected to decrease heavy fuel oil yield to about 10 percent of refinery throughput by 1970. Based on Petroleum and Natural Gas Conservation Board estimates of Alberta refinery crude oil throughput of 38,000,000 barrels[1/] in 1970, this yield will result in a heavy fuel oil production of 3,800,000 barrels.

The major market for Alberta heavy fuel oil has been as a fuel for steam locomotives. This market, which presently represents about 3,000,000 barrels of heavy fuel oil per year, will disappear when the dieselization program of the railroads is completed about 1961.

The delivered prices of heavy fuel oil to various industrial centers are shown in Table III. Because of the anticipated large surplus of heavy fuel oil, no price increases in terms of constant dollars have been forecast for this product. The current spread between heavy fuel oil and natural gas prices on an equivalent natural gas basis is so great that even if substantial cuts in heavy fuel oil prices were made, it would still not be competitive with natural gas. However, when the anticipated surplus of heavy fuel oil develops, there will be sufficient economic pressure on the price of this product to cause the oil refineries to use heavy fuel oil as a substitute for natural gas. The refineries will make every effort to find outlets for heavy fuel oil over and above that which can be used as refinery fuel.

Light Fuel Oil

Because of increased demands for light fuel oils both for railroad diesel units and for diesel-powered drilling rigs, it is expected that

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1/ Government of the Province of Alberta, "Alberta's Economic Prospects," December 1955, Table 4-2, page 112. Estimates adjusted for imports of crude oil from Saskatchewan.

there will be a 10 to 15 percent increase in the price of these oils during the 1960-1970 period. This price increase in terms of constant dollars is shown in Table III. Most of the drilling rigs operating in Alberta are powered by diesel engines.

Refinery Gases

Production of refinery gases is dependent upon refinery throughput and the types of refining units in use. Although the supply of refinery gases should increase considerably during the forecast period because of increases in refinery throughput, the bulk of these gases will be used by the refineries as fuel or raw material and consequently will not have any impact on the established pattern of industrial fuel consumption. In addition, some refinery gases will be available as raw materials to certain chemical manufacturers.

Liquefied Petroleum Gases

Complete statistical data on propane and butane are not available in Canada at present. In 1956, Alberta production of propane totaled 926,000 barrels, equivalent to 3.7 Bcf natural gas. Production of butane in this same year totaled 592,000 barrels, equivalent to 2.5 Bcf natural gas. Although detailed forecasts of propane and butane production are not part of this study, it appears certain that there will be substantial increase in production of these materials because of the anticipated increase in production of natural gas in the province.

The major markets for propane are for cooking and space heating in the rural areas of Alberta. In 1956, the apparent consumption of propane for industrial uses in Alberta was only about 0.5 Bcf natural gas equivalent. This amount is insignificant when compared with total energy demand. Propane is presently selling in Alberta for 5.5 cents per imperial gallon (f.o.b. plant) which is equivalent to 46 cents per Mcf, or nearly three times the existing average industrial natural gas price. At this price propane is not a competitive fuel in the industrial markets, except possibly for peak load shaving. To be competitive with natural gas at current prices propane would have to be available at about 1.6 cents per imperial gallon.

Butane is presently selling in Alberta for approximately 3 cents per imperial gallon (f.o.b. plant) which is equivalent to about 24 cents per Mcf, or nearly double the present average price of industrial natural gas. At this price level butane is not a potential fuel in the

industrial market. However it can be used as a raw material as indicated by the announcement of a butadiene plant, using butane as a feed stock, at Red Deer. It is also valuable in the refining industry for gasoline blending and upgrading. The continued development of Prairie Province markets and the possibility of export of these materials would indicate that propane and butane will probably not enter the industrial gas fuel market.

Hydroelectric Power

As outlined earlier, hydroelectric power is not a competitive fuel but is included to complete the total industrial energy picture. In 1955, hydroelectric stations generated 58 percent of total power in Alberta but only 49 percent in 1956. By 1970, only 34 percent of power generated in the province is expected to be hydroelectric. Consequently, the contribution of hydroelectric power to total industrial energy requirements will be very small. Figure 5 shows the location of the major electric power stations in Alberta at the end of 1956. Estimated fuel requirements for thermal electric power stations expressed in terms of natural gas equivalents are 27 Bcf in 1960, 40 Bcf in 1965, and 57 Bcf in 1970. These estimates of fuel requirements are based on forecasts of electric power generation as shown in Appendix H.

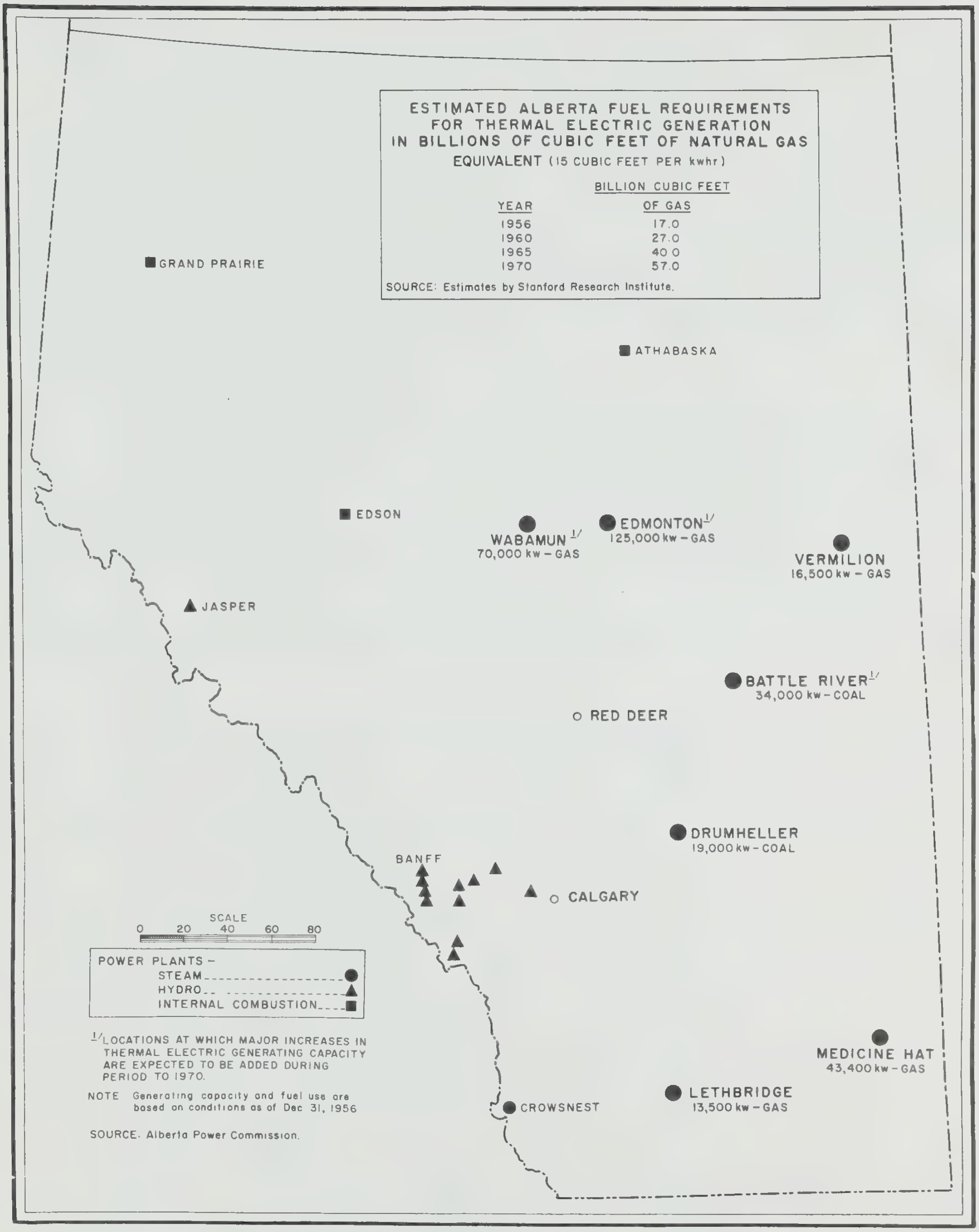

FIG. 5

ELECTRIC POWER STATIONS IN ALBERTA

Section V

LOW-COST NATURAL GAS AS A FACTOR IN THE INDUSTRIAL GROWTH OF ALBERTA

In order to review the effect of low-cost natural gas on industrial growth in Alberta, a number of industrial firms in the province were contacted with regard to the relative importance of low-cost industrial fuel in their decision to locate in Alberta. In addition, published literature on this subject was studied.

A number of studies have been made to determine the relative importance of various location factors. One of the most useful of these studies was made by the Texas Engineering Experiment Station in 1954.[1/] This study was based on an analysis of information supplied by more than 400 industrial plants located in Texas. The companies were asked to rate specific location factors in descending order of importance. In determining the relative importance of each location factor, a weighting system was applied, the results of which are shown below:

Factor	Percent Weight
Market	18.9
Labor	14.5
Raw materials	12.3
Transportation	7.7
Building	7.5
Distribution	7.0
Site	6.7
Living conditions	6.2
Climate	3.9
Industrial fuel	3.4
Financial help	2.2
Water	2.2
Taxes	2.1
Industrial power	1.9
Laws and regulations	1.1
Miscellaneous	2.4

1/ Research Report No. 49, October 1954, Texas Engineering Experiment Station, College Station, Texas.

The results were further broken down into 14 industrial classifications. Industrial fuel ranked higher than tenth in the order of importance in only five classifications, as follows: food, eighth; paper products, ninth; chemical, sixth; petroleum, sixth; and stone, clay, and glass, fifth.

The results of this survey are substantiated by studies conducted by other groups. In his book entitled "Plant Location," Leonard C. Yascen[1/] commented that "most industries find the locational significance of fuels to be negligible. Within given economic regions slight differentials in fuel costs are usually far outweighed by other variable factors."

Mr. Maurice Fulton, a partner in the same firm, made the following reference to the importance of fuel as a plant location factor in an article entitled "Plant Location--1965"[2/]:

> "...Low-cost power alone is not sufficient to create an industrial pattern. Industries directly oriented to fuel, like coke ovens and carbon black manufacturing, are very few. Only where low-power cost happens to be combined with raw materials and markets is there any basis for a well-diversified industrial complex."

The above articles also mentioned that extension of gas transmission lines would reduce the locational "pull" of gas-producing areas and that greater use of coal as a fuel would become apparent in the future. More efficient coal mining methods and increased wellhead costs of natural gas would mean that coal will become more competitive with natural gas.

A Stanford Research Institute study made for the Oregon Development Commission in 1956 came to similar conclusions as the foregoing studies.[3/]

The majority of industries contacted indicated that they located in Alberta primarily because of the growing importance of Prairie Province markets or proximity to raw materials rather than to availability of low-cost fuels. The only plants which located in Alberta primarily because

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1/ Senior Partner, Fantus Factory Locating Service.

2/ Harvard Business Review, March-April 1955.

3/ Stanford Research Institute "Evaluation of Industrial Opportunities for Oregon," August 1956.

of the availability of low-cost natural gas have been ammonia and polyethylene plants. The 1956 total natural gas consumption of these plants was about 10 billion cubic feet, or 18 percent of the total estimated industrial gas consumption in the province. These industries use natural gas primarily as a raw material.

A number of factors indicate that major expansion of ammonia production in Alberta is unlikely during the period of this forecast. The total capacity of existing plants in Alberta exceeds present demand within the province. In addition, new ammonia processes have been developed which utilize raw materials other than natural gas. Finally, since costs of transporting ammonia are relatively high, and since construction of gas transmission lines will increase the availability of natural gas, future expansion of ammonia plants may be made closer to major market areas. For example, the newest ammonia plants have located close to the large markets in California, the Pacific Northwest, and the Midwest despite the relatively high cost of natural gas in these areas.

The polyethylene plant in Alberta recently announced plans to double the capacity of the existing plant. Although the natural gas used as raw material for the polyethylene plant in Alberta is probably a lower cost raw material than refinery gases--the usual raw material for polyethylene production--the freight charges to eastern markets eliminate much if not all of this advantage.

At present no carbon black plants are in operation in western Canada. The possibility of establishing a carbon black plant in Alberta has been investigated at various times in the past, but the economics of such an operation have probably been the major deterrent.

In summary, it does not appear either that carbon black will be produced or that there will be any major expansion of ammonia production in Alberta during the forecast period. Some expansion of the polyethylene industry can be expected. It is recognized that petrochemical plants designed to use propane or butane as raw materials may locate in Alberta. Since these plants would use natural gas only as a fuel, the price and availability of natural gas will probably not be a major factor in the location of new facilities.

As indicated above, the future growth of the petrochemical industry based on natural gas as a raw material will probably not be as great as in the past; nevertheless, general industrial expansion in Alberta is expected to continue at its present rate. This expansion will include both development of primary industries using the natural resources of the province as raw materials, and growth of secondary industries supplying these primary industries.

Appendix A

ENERGY CONVERSION DATA AND ASSUMPTIONS

Burning Efficiencies of Fuels				Heat Values of Fuels	
	Burning Efficiencies			Fuel	Heat Value
Energy Source	Domestic Use (percent)	Commercial Use (percent)	Industrial Use (percent)	Natural Gas	1,000 Btu per cubic foot
				Coal	
				Provincial average	8,750 Btu per pound
				Edmonton, Wabamun	
Natural Gas	75	75	78	& Hal Kirk	8,500 Btu per pound
Coal	60	65	73	Drumheller	9,000 Btu per pound
Heavy Fuel Oil	—	75	78	Lethbridge	10,500 Btu per pound
Light Fuel Oil	75	75	78	Heavy Fuel Oil	176,000 Btu per imp. gal.
Propane	75	75	78	Light Fuel Oil	161,500 Btu per imp. gal.
Butane	—	75	78	Propane	114,000 Btu per imp. gal.
Refinery Gases	—	—	78	Butane	123,000 Btu per imp. gal.
Hydroelectricity	100	100	100	Hydroelectricity	3,412 Btu per kwh

Notes:

1. The equivalent prices of competitive fuels in the Edmonton and Red Deer areas as shown in Table III were calculated on the basis of 960 Btu per cubic foot gas. Those for the Calgary and Lethbridge areas were calculated on the basis of 1,020 Btu per cubic foot gas. All natural gas consumption data in the report are based upon 1,000 Btu per cubic foot gas.

2. The coal prices shown in Table III are based on slack or run-of-the-mine coal potentially available in quantity at the lowest price in the market areas. The average heat value of Alberta coal indicated in the above table is the estimated average heat value of coal consumed in Alberta, exclusive of railway use.

Appendix B

METHOD OF FORECASTING ENERGY REQUIREMENTS

1. Straight-line projections of Alberta per capita energy requirements by end use based on historical data from 1949-1956 were made to 1960, 1965, and 1970.

2. The per capita energy requirements obtained from the above projections were combined with the British Columbia Research Council population estimates for Alberta (see table on population following) to give values of total energy requirements by end use for the years 1960, 1965, and 1970. These values provided an upper limit or what was considered a high forecast of energy requirements.

3. The 1956 per capita energy requirements were combined with the same population forecast as noted above to provide another set of values for energy requirements by end use for the years 1960, 1965, and 1970. This set of values provided a lower limit or what was considered a low forecast.

4. The final forecast was based on the assumption that up to 1960 the actual per capita energy requirements would follow the trend line or the high forecast but that in 1965 and 1970 the increase in per capita energy requirements would be less than those indicated by the trend line. In 1965 and 1970 it was assumed that the energy requirements of the province would be midway between that indicated by the above-mentioned high and low forecasts.

FORECASTS OF ENERGY REQUIREMENTS
(Billions of Cubic Feet Natural Gas Equivalent)

	1960			1965			1970		
	High	Low	Final	High	Low	Final	High	Low	Final
Domestic	60	53	60	82	62	76	111	73	92
Commercial	33	26	33	50	31	45	75	36	56
Industrial	100	84	100	156	98	141	247	115	181
Total	193	163	193	288	191	262	433	224	329

POPULATION OF ALBERTA
(In Thousands of Persons)
1949-1970

Year	Actual Population	B.C. Research Council Forecast	Conservation Board Forecast	Alberta Bureau of Statistics Forecast
1949	885			
1950	913			
1951	939			
1952	970			
1953	1,002			
1954	1,039			
1955	1,066			
1956	1,123			
1960		1,260	1,270	1,143
1965		1,478	1,440	1,253
1970		1,734	1,600	1,376

Sources: British Columbia Research Council, "Population Trends in Canada, British Columbia, Alberta, and Saskatchewan, 1956-1975." Petroleum and Natural Gas Conservation Board, Province of Alberta, "Natural Gas Reserves of the Province of Alberta and Other Related Data," January 1957. Alberta Bureau of Statistics, "Alberta's Economic Prospects."

Appendix C

TOTAL ENERGY REQUIREMENTS BY END USE IN ALBERTA
(Exclusive of Transportation Requirements)
1949-1970

Year	Domestic		Commercial		Industrial		Total Bcf
	Bcf 1/	Percent Total	Bcf	Percent Total	Bcf	Percent Total	
1949	29.4	37.2	12.8	16.2	36.8	46.6	79.0
1950	33.6	37.9	14.3	16.1	40.7	46.0	88.6
1951	34.5	37.7	15.1	16.5	41.9	45.8	91.5
1952	35.7	36.7	16.9	17.4	44.6	45.9	97.2
1953	37.0	35.7	18.4	17.7	48.3	46.6	103.7
1954	41.0	34.7	20.3	17.2	56.9	48.1	118.2
1955	45.9	34.0	22.0	16.3	67.1	49.7	135.0
1956	48.8	33.3	23.6	16.1	74.3	50.6	146.7
1960	60.0	31.1	33.0	17.1	100.0	51.8	193.0
1965	76.0	29.0	45.0	17.2	141.0	53.8	262.0
1970	92.0	28.0	56.0	17.0	181.0	55.0	329.0

1/ Billions of cubic feet natural gas equivalent.

Sources: 1949-1955--Dominion Bureau of Statistics; The Petroleum and Natural Gas Conservation Board, Province of Alberta; The Alberta Bureau of Statistics; and The Alberta Power Commission.
1956-1970--Estimates by Stanford Research Institute.

Appendix D

TOTAL ENERGY REQUIREMENTS BY SOURCE IN ALBERTA
(Exclusive of Transportation Requirements)
1949-1970

Year	Natural Gas		Coal		Fuel Oils		LPG and Refinery Gas		Hydroelectric		Total Bcf
	Bcf 1/	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	
1949	42.4	53.7	24.5	31.0	6.8	8.6	3.9	4.9	1.4	1.8	79.0
1950	47.8	54.0	23.9	27.0	10.5	11.9	5.0	5.6	1.4	1.6	88.6
1951	53.1	58.0	20.2	22.1	10.3	11.3	5.9	6.4	2.0	2.2	91.5
1952	57.2	58.8	17.3	17.8	12.2	12.6	7.6	7.8	2.9	3.0	97.2
1953	65.8	63.4	14.8	14.3	12.1	11.7	8.5	8.2	2.5	2.4	103.7
1954	80.2	67.9	15.0	12.6	11.5	9.7	8.2	6.9	3.4	2.9	118.2
1955	95.5	70.7	15.2	11.3	11.0	8.1	9.4	7.0	3.9	2.9	135.0
1956	106.5	72.6	14.6	10.0	11.0	7.4	10.7	7.3	3.9	2.7	146.7
1960	134.1	69.5	15.8	8.2	21.4	11.1	16.7	8.6	5.0	2.6	193.0
1965	178.5	68.1	29.0	11.0	25.1	9.6	24.0	9.2	5.4	2.1	262.0
1970	222.0	67.5	41.9	12.7	28.6	8.7	29.1	8.8	7.4	2.3	329.0

Note: Estimates for 1960-1970 are based on the assumption that, in general, average industrial natural gas prices will not exceed 20 cents per Mcf.

1/ Billions of cubic feet natural gas equivalent.

Sources: 1949-1955--Dominion Bureau of Statistics; The Petroleum and Natural Gas Conservation Board, Province of Alberta; The Alberta Bureau of Statistics; and The Alberta Power Commission.
1956-1970--Estimates by Stanford Research Institute.

Appendix E

DOMESTIC ENERGY REQUIREMENTS BY SOURCE IN ALBERTA
1949-1970

Year	Natural Gas		Coal		Heating Oils		Propane		Hydroelectric		Total Bcf
	Bcf 1/	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	
1949	15.4	52.2	13.1	44.4	0.5	1.7	0.2	0.7	0.3	1.0	29.5
1950	17.0	50.6	14.2	42.3	1.7	5.0	0.4	1.2	0.3	0.9	33.6
1951	18.3	53.1	13.2	38.3	1.9	5.5	0.6	1.7	0.5	1.4	34.5
1952	20.1	56.1	12.1	33.8	2.0	5.6	0.9	2.5	0.7	2.0	35.8
1953	23.0	62.0	10.0	26.9	2.3	6.2	1.1	3.0	0.7	1.9	37.1
1954	24.5	59.8	11.1	27.1	3.3	8.0	1.2	2.9	0.9	2.2	41.0
1955	28.0	61.0	11.6	25.3	3.3	7.2	1.9	4.1	1.1	2.4	45.9
1956	30.8	63.1	11.5	23.6	3.3	6.7	2.1	4.3	1.1	2.3	48.8
1960	38.4	64.0	10.0	16.7	4.5	7.5	5.7	9.5	1.4	2.3	60.0
1965	50.2	66.0	8.0	10.5	6.0	7.9	10.3	13.6	1.5	2.0	76.0
1970	62.6	68.0	7.0	7.6	7.5	8.2	12.9	14.0	2.0	2.2	92.0

1/ Billions of cubic feet natural gas equivalent.

Sources: 1949-1955—Dominion Bureau of Statistics; The Petroleum and Natural Gas Conservation Board, Province of Alberta; The Alberta Bureau of Statistics; and The Alberta Power Commission.
1956-1970—Estimates by Stanford Research Institute.

Appendix F

COMMERCIAL ENERGY REQUIREMENTS BY SOURCE IN ALBERTA
1949-1970

Year	Natural Gas		Coal		Heating Oils		Propane		Hydroelectric		Total Bcf
	Bcf1/	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	
1949	10.8	84.3	1.6	12.5	0.2	1.6	—	—	0.2	1.6	12.8
1950	11.7	81.8	1.7	11.9	0.6	4.2	—	—	0.3	2.1	14.3
1951	12.4	82.1	1.6	10.6	0.6	4.0	0.1	0.7	0.4	2.6	15.1
1952	14.1	83.4	1.5	8.9	0.6	3.6	0.2	1.2	0.5	2.9	16.9
1953	15.8	85.9	1.2	6.5	0.8	4.3	0.2	1.1	0.4	2.2	18.4
1954	17.2	84.7	1.3	6.4	1.1	5.4	0.2	1.0	0.5	2.5	20.3
1955	18.5	84.1	1.4	6.4	1.1	5.0	0.3	1.3	0.7	3.2	22.0
1956	20.1	85.1	1.4	5.9	1.1	4.7	0.3	1.3	0.7	3.0	23.6
1960	28.0	85.0	1.3	3.9	1.5	4.5	1.3	3.9	0.9	2.7	33.0
1965	38.2	85.0	1.1	2.4	2.0	4.4	2.7	6.0	1.0	2.2	45.0
1970	47.6	85.0	1.0	1.8	2.5	4.5	3.6	6.4	1.3	2.3	56.0

1/ Billions of cubic feet natural gas equivalent.

Sources: 1949-1955—Dominion Bureau of Statistics; The Petroleum and Natural Gas Conservation Board, Province of Alberta; The Alberta Bureau of Statistics; and The Alberta Power Commission.
1956-1970—Estimates by Stanford Research Institute.

Appendix G

INDUSTRIAL ENERGY REQUIREMENTS BY SOURCE IN ALBERTA
(Exclusive of Transportation Requirements)
1949-1970

Year	Natural Gas		Coal		Fuel Oils		LPG and Refinery Gas		Hydroelectric		Total Bcf
	Bcf 1/	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	Bcf	Percent Total	
1949	16.2	44.0	9.8	26.7	6.1	16.6	3.8	10.3	0.9	2.4	36.8
1950	19.1	46.9	8.0	19.7	8.2	20.1	4.6	11.3	0.8	2.0	40.7
1951	22.4	53.5	5.4	12.9	7.8	18.6	5.1	12.1	1.2	2.9	41.7
1952	23.0	51.6	3.7	8.3	9.6	21.5	6.6	14.8	1.7	3.8	44.6
1953	27.0	55.9	3.6	7.5	9.0	18.6	7.2	14.9	1.5	3.1	48.3
1954	38.5	67.7	2.6	4.6	7.1	12.5	6.8	11.9	1.9	3.3	56.9
1955	49.0	73.0	2.2	3.3	6.5	9.7	7.3	10.9	2.1	3.1	67.1
1956	55.6	74.9	1.7	2.3	6.5	8.7	8.4	11.3	2.1	2.8	74.3
1960	67.7	67.7	4.5	4.5	15.4	15.4	9.7	9.7	2.7	2.7	100.0
1965	90.1	63.9	19.9	14.1	17.1	12.1	11.0	7.8	2.9	2.1	141.0
1970	111.8	61.7	33.9	18.7	18.6	10.3	12.6	7.0	4.1	2.3	181.0

Note: Estimates for 1960-1970 are based on assumption that, in general, average industrial natural gas prices will not exceed 20 cents per Mcf.

1/ Billions of cubic feet natural gas equivalent.

Sources: 1949-1955--Dominion Bureau of Statistics; The Petroleum and Natural Gas Conservation Board, Province of Alberta; The Alberta Bureau of Statistics; and The Alberta Power Commission.
1956-1970--Estimates by Stanford Research Institute.

Appendix H

ELECTRIC POWER GENERATION IN CENTRAL ELECTRIC STATIONS IN ALBERTA 1949-1970

Year	Population (thousands)	Electrical Power Generated			
		Kwh per Capita	Total Kwh (millions)	Thermal, Percent of Total	Thermal Kwh (millions)
1949	885	905	801	54.7	495
1950	913	952	869	60.8	528
1951	939	1,123	1,055	49.8	527
1952	970	1,250	1,213	35.3	428
1953	1,002	1,338	1,341	40.6	543
1954	1,039	1,443	1,499	42.8	642
1955	1,066	1,621	1,728	41.8	724
1956	1,123	1,800	2,019	51.5	1,040
1960	1,260	1,980	2,500	63.0	1,580
1965	1,178	2,400	3,550	66.0	2,340
1970	1,734	2,910	5,050	66.0	3,330

Sources: 1949-1956--Alberta Power Commission.
1960-1970--Forecast of per capita power generation by Alberta Power Commission.
1960-1970--Forecast of total and thermal power generation by Stanford Research Institute.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
NORTHWESTERN UTILITIES, LIMITED

Transmission Economics

Two studies of the cost of transporting gas by pipe lines are presented on the following Pages 2, 3, and 4. The first is given on Pages 2 and 3 and deals with long-distance transportation at 780 pounds maximum operating pressure, involving the use of compressors to boost pressure en route. The second is given on Page 4 and deals with the costs involved in pipe lines of 100 mile length, operating at a maximum pressure of 500 pounds without compressors, it being assumed that these pipe lines are constructed by the companies.

The purpose of these studies is to show the economies possible by the use of high pressure, large diameter pipe lines operating at high load factor. The first study assumes that the design and construction of the pipe line and compressor facilities are carried out by consultants and contractors retained or employed for such purposes. Consequently the capital costs reflect the profits which are appropriate to these functions and the administrative and overhead costs associated therewith. The second assumes that the facilities are incorporated in the companies' utility rate base at "out-of-pocket" cost, exclusive of engineering and administrative costs, since these are incurred in any event in other normal utility operations.

X The last tabulation on Page 3 shows, for the first case, that the annual unit cost per 100 miles varies from less than 2¢ per Mcf for a 36 inch pipe line operating at 100% load factor to about 7¢ per Mcf for a 20 inch pipe line operating at 50% load factor.

On Page 4, the annual unit cost for a 100 mile pipe line constructed by these companies is shown to vary from 1¢ per Mcf in the case of a 30 inch pipe line operating at 100% load factor to more than 60¢ per Mcf in the case of a 4 inch pipe line operating at 40% load factor.

X It is important to note that large quantities of gas can be transported 2,000 miles through a 36 inch pipe line, operating at 100% load factor, at lower cost per Mcf (20 x 1.77¢ = 35.4¢) than small quantities transported for 100 miles through a 4 inch pipe line at 40% load factor (61.4¢), even though the economies inherent to construction by utility companies are reflected in the latter case. This explains why residents of some small communities in Alberta cannot be served, particularly where gas has to compete with low cost local coal supplies, while it is economically feasible to supply residents in Eastern Canada with Alberta gas.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES, LIMITED

Economics of Long Distance Transportation of Gas

(From analysis of figures submitted in Export Hearings, May 1953 - costs adjusted to present levels)

Assume compressor stations @ 75 mi. spacing
Inlet pressure - 780 psig (790 psig at compressor header)
Outlet pressure - 550 psig (545 psig at compressor header)
Compression ratio - 1.44
H.P. per MMcf/day - 17.4

Diameter & wall thickness	36" x .375	30" x .3125	24" x .25	20" x .2085
Daily Capacity - MMcf @ 14.4# & 60° F	826	517	289	180
Compressor H.P. (One station)	14,400	9,000	5,000	3,100
Daily compressor fuel MCF	3,460	2,160	1,200	745

Capital Costs	36"	30"	24"	20"
75 mi. pipeline @ $5,000 per inch mile	$13,500,000	$11,250,000	$9,000,000	$7,500,000
1 Compressor Stn. @(1st (4000 HP (@ $400 (Bal. @ ($300	4,720,000	3,100,000	1,900,000	1,240,000
Total Capital Cost	$18,220,000	$14,350,000	$10,900,000	$8,740,000

Annual Costs				
Return - 7.5%) Depreciation - 3.5%)14.5% Income Taxes - 3.5%)	$ 2,640,000	$ 2,080,000	$ 1,580,000	$ 1,267,000
Transmission, Operation & Maintenance	66,000	57,700	48,700	43,500
Compressor Operation & Mtce. @ $25/H.P.	360,000	225,000	125,000	77,500
Compressor Fuel Gas @ 15¢/MCF	189,600	118,300	65,700	40,800
Dispatching(1)	63,900	42,400	26,100	18,200
Measuring(2)	42,600	28,300	17,400	12,100
Admin. & General Expense(3)	292,900	194,400	119,500	83,200
Local Taxes @ 1% of Capital	182,200	143,500	109,000	87,400
Total Annual Costs	$3,837,200	$2,889,600	$2,091,400	$1,629,700

	36"	30"	24"	20"
Daily Capacity - MMcf/day	826	517	289	180
Less Compressor Fuel for say 10 Stations	35	22	12	7.5
Net Sales Capacity - MMCF/day	791	495	277	172.5
Annual Sales Volume				
@ 100% L.F. - MMCF	289,000	181,000	101,000	63,000
@ 75% L.F. - MMCF	217,000	135,500	76,000	47,000
@ 50% L.F. - MMCF	144,500	90,500	50,500	31,500
Total Annual Costs	$3,837,300	$2,889,600	$2,091,400	$1,629,700
Annual Costs per MCF per 75 miles				
100% L.F.	1.33¢	1.60¢	2.07¢	2.59¢
75% L.F.	1.77	2.13	2.75	3.47
50% L.F.	2.65	3.19	4.14	5.18
Annual Cost per MCF per 100 miles				
100% L.F.	1.77¢	2.13¢	2.76¢	3.46¢
75% L.F.	2.36	1.84	3.66	5.63
50% L.F.	3.54	4.25	5.52	6.91

Notes: (1) Dispatching expense @ 15% of Transmission & Compressor operation and maintenance, exclusive of fuel gas.

(2) Measuring expense @ 10% of Transmission & Compressor operation and maintenance, exclusive of fuel gas.

(3) Admin. & General Expense @ 55% of all other operation & maintenance (exclusive of local taxes and fuel gas)

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
NORTHWESTERN UTILITIES, LIMITED

Economics of Utility Constructed Transmission Lines in Alberta

Assumptions - Length 100 miles
Inlet Pressure - 500 psig
Outlet Pressure - 100 psig

Diameter & Wall Thickness	30" x 0.250"	24" x 0.250"	16" x 0.219"	12-3/4" x 0.203"	8-5/8" x 0.188"	4-1/2" x 0.156"
Daily Capacity MMCF @ 14.4# & 60°F	401	221	75.2	41.2	14.3	2.54
Annual Throughput - MMCF						
@ 100% Load Factor	146,400	80,700	27,400	15,000	5,220	927
80% Load Factor	117,100	64,600	21,900	12,000	4,180	742
60% Load Factor	87,800	48,400	16,400	9,000	3,130	556
40% Load Factor	58,600	32,300	11,000	6,000	2,090	371
Capital Cost @ $3250 per inch mile	$9,750,000	$7,800,000	$5,200,000	$4,140,000	$2,800,000	$1,460,000
Annual Costs						
Return @ 7.5%						
Inc. Taxes @ 3.5%						
Deprec. @ 3.0%						
Total fixed charges @ 14.0%	$1,365,000	$1,092,000	$ 728,000	$ 580,000	$ 392,000	$ 204,000
Operation & Mtce. Expense	77,000	65,000	50,000	43,000	34,000	24,000
Total Annual Costs*	$1,442,000	$1,157,000	$ 778,000	$ 623,000	$ 426,000	$ 228,000
Annual Costs - cents per Mcf						
@ 100% Load Factor	1.0¢	1.4¢	2.8¢	4.2¢	8.2¢	24.6¢
80% Load Factor	1.2	1.8	3.6	5.2	10.2	30.7
60% Load Factor	1.6	2.4	4.7	6.9	13.6	41.7
40% Load Factor	2.5	3.6	7.1	10.4	20.4	61.4

* Exclusive of administrative and general expense.

ALBERTA AND SOUTHERN GAS CO. LTD.

- and -

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

NORTHWESTERN UTILITIES, LIMITED

AGREEMENT

THIS AGREEMENT made this 9th day of August 1957, by and between ALBERTA AND SOUTHERN GAS CO. LTD., a corporation, hereinafter called "Gas Company," and CANADIAN WESTERN NATURAL GAS COMPANY LIMITED, a corporation, and NORTHWESTERN UTILITIES, LIMITED, a corporation, hereinafter called "Alberta Utilities,"

W I T N E S S E T H:

WHEREAS Gas Company proposes to purchase natural gas within the Province of Alberta for export from said Province and ultimate transportation to the State of California and to apply as soon as practicable to the Oil and Gas Conservation Board of Alberta for a permit to export from the Province a minimum of about 400 million cubic feet of natural gas per day, and for such purposes to procure such other permits, certificates and authorizations as may be required under applicable laws and regulations; and

WHEREAS Alberta Utilities are public utility corporations engaged in the natural gas business within the Province of Alberta; and

WHEREAS the parties hereto recognize that Alberta Utilities shall have priority as to the gas supplies of Gas Company

to the extent that the gas supplies of Alberta Utilities are insufficient to meet their natural gas requirements, and desire to make reciprocal sales of gas, and to co-operate with each other, all as hereinafter set forth; and

WHEREAS Gas Company proposes to enter into gas transportation contracts with its related company, Alberta and Southern Transmission Co. Ltd. and may enter into such contracts with other gas pipe line companies, and Alberta Utilities propose to use their gas pipe line facilities and may enter into gas transportation contracts with gas pipe line companies to the end that each of the parties hereto shall be able to perform its obligations herein contained.

NOW, THEREFORE, it is hereby agreed as follows:

ARTICLE I - PURCHASE OF ANNUAL VOLUMES OF GAS BY ALBERTA UTILITIES

1. Gas Company shall sell and deliver to Alberta Utilities and Alberta Utilities shall purchase and take from Gas Company such annual and maximum daily volumes of natural gas as may from year to year be requested at least one year in advance by Alberta Utilities and agreed to by Gas Company. In arriving at such agreement, consideration will be given to: (1) Alberta Utilities' agreement to take such gas at as high a load factor as practicable; (2) the annual market requirements of Alberta Utilities; and (3) the other sources

of supply available to Alberta Utilities. Provided, however, such annual volumes shall in no event be less than the annual volumes Alberta Utilities shall elect to purchase at not less than seventy percent (70%) annual load factor; and provided further, that such annual volumes shall in no event exceed the volumes required by Alberta Utilities to meet the annual requirements of their customers referred to in section (a) of paragraph 1 of Article II and the annual requirements of their customers referred to in section (b) of paragraph 1 of Article II up to the annual quantities set forth in Schedule "A" annexed hereto and hereby incorporated herein after first making reasonable use of their other sources of supply.

2. If the parties should fail to agree upon such volumes within the limitations expressed in the foregoing provisos, such volumes shall be determined by arbitration, in the manner hereinafter provided, within the said limitations.

3. Alberta Utilities shall pay Gas Company for all such gas purchased by them a price equal to the weighted average field price paid by Gas Company in the Province of Alberta for natural gas in the month such gas is delivered, plus an appropriate transmission charge.

ARTICLE II - PURCHASE OF ADDITIONAL GAS BY ALBERTA UTILITIES

1. Gas Company shall sell and deliver to Alberta Utilities such additional quantities of gas as Alberta Utilities shall require while they are making maximum use of their other sources of supply to the extent that their then existing facilities permit, including gas referred to in Article I, if any, in order to meet:

(a) the actual natural gas requirements of their domestic, commercial, and small industrial customers and

(b) the estimated maximum daily natural gas requirements for their large industrial customers shown on Schedule "A".

"Large industrial customer" shall mean any customer whose average consumption of natural gas exceeds 500 Mcf/day. All other customers shall be considered domestic, commercial, or small industrial.

2. The estimated daily and annual requirements shown on Schedule "A" shall be revised as appropriate by Alberta Utilities and Gas Company prior to or during the hearing of any application of Gas Company to the Oil and Gas Conservation Board to increase the volume of gas covered by its permit or permits to export gas from Alberta then in effect; provided, however, that no such revised estimate shall be applied retroactively if such application of such estimate could operate to decrease the volume of gas which Gas Company may export under its said export permit or permits then in effect; and provided further that

in revising any such estimate Alberta Utilities shall not be required to reduce such estimate below the volumes shown on any earlier estimate.

3. Gas Company shall sell said additional gas to Alberta Utilities from any source of natural gas supply within the Province of Alberta which it owns or has available to it under contract.

4. Whenever Alberta Utilities desire to purchase additional gas they shall give reasonable notice to Gas Company specifying the time and volume required. Gas Company shall not be obligated to install or cause to be installed or enlarge or cause to be enlarged pipelines or compressor facilities to make any such deliveries. Alberta Utilities shall have only the obligation to install such facilities as are required to take such additional gas to their market areas from points at which Gas Company can make such gas available.

5. Alberta Utilities shall pay Gas Company for all additional gas purchased by them, at the option of Alberta Utilities, either (a) 1.3 times the weighted average field price paid by Gas Company in the Province of Alberta for natural gas in the month the additional gas is delivered, plus an appropriate transmission charge, or (b) 1.3 cubic feet of gas for each cubic foot of additional gas purchased (such payment gas to be delivered at the mutual convenience of the parties).

6. All contracts made by Gas Company for the export of gas from the Province of Alberta shall be subject to the foregoing obligations in favor of Alberta Utilities.

ARTICLE III - SALES OF GAS BY ALBERTA UTILITIES TO GAS COMPANY

1. Prior to the first hearing before the Oil and Gas Conservation Board for a permit for Gas Company to export gas from the Province of Alberta, the parties hereto shall estimate the daily volume of gas, if any, hereinafter called "firm gas," which Alberta Utilities will be able and willing to sell and deliver to Gas Company and which Gas Company will be able and willing to buy and take from Alberta Utilities.

2. After such initial estimate of firm gas has been made Alberta Utilities and Gas Company shall enter into a contract for the sale and purchase of firm gas, under terms and conditions corresponding to those contained in gas purchase contracts made by Gas Company for purchase of gas in Alberta prior to said hearing. At any time after the commencement of deliveries of firm gas the parties hereto may agree to increase or decrease the daily contract volume of firm gas, and either party shall have the right, upon three (3) years' written notice to the other, to make a unilateral reduction in the daily contract volume of firm gas.

3. Gas Company shall pay Alberta Utilities for firm gas purchased by it the weighted average price paid by Gas Company to producers of natural gas in the Province of Alberta for gas purchased under the same terms and conditions (including quality, pressure and

load factor) in the month such gas is delivered, plus an appropriate transmission charge.

4. In addition to firm gas, Alberta Utilities shall sell and deliver and Gas Company shall buy and receive such additional volumes of natural gas as may be tendered by Alberta Utilities and as Gas Company may be able to take and beneficially use without risking inability to meet purchase obligations contained in its other gas purchase contracts. Gas Company shall pay to Alberta Utilities for such gas the weighted average field price paid by Alberta Utilities for all gas purchased by them in the month such gas is delivered, plus an appropriate transmission charge.

5. The obligations of Alberta Utilities respecting entry into any contract for the sale of gas as provided in paragraph 2 of this Article III or respecting any sale of gas as provided in paragraph 4 of this Article III shall not become effective or binding upon Alberta Utilities unless and until any such contract or sale shall have been approved by The Board of Public Utility Commissioners of the Province of Alberta.

6. Notwithstanding anything to the contrary contained herein, Gas Company shall not be obligated under this Article III to purchase any volume of natural gas from Alberta Utilities if such purchase would bring into operation any favored nations clause affecting any gas purchase contract between Gas Company and any producer of gas within

the Province of Alberta.

ARTICLE IV - INTERCONNECTION AND RECIPROCAL TRANSMISSION SERVICE

The parties hereto will mutually agree as to points of delivery and will provide transmission service for each other to the extent that they control facilities with capacity available for such service. An appropriate charge shall be paid for such service.

ARTICLE V - CO-OPERATION

The parties will consult with each other in the planning of the facilities which are needed to give effect to this agreement with the ultimate objective of assuring that the facilities of each party and the gas reserves of the Province of Alberta are utilized as efficiently as possible.

ARTICLE VI - TERM

This agreement shall be effective from the date hereof and shall continue for the term of the export permit and any supplements thereof and extensions thereto obtained by Gas Company from the Oil and Gas Conservation Board.

ARTICLE VII - ARBITRATION

Any dispute or difference of interpretation concerning this contract which cannot be settled by mutual accord between the parties

A.P.

shall be submitted to and settled by arbitration. If the parties hereto are unable to agree on any matter, where, under any provision of this contract, mutual agreement between the parties as to such matter is contemplated as being necessary for the implementation of the contract, then such matter shall be submitted to and settled by arbitration. Alberta Utilities shall be deemed to be one party. Any such dispute or difference or matter shall be referred to a single arbitrator if the parties agree upon one, or otherwise to three arbitrators, one to be appointed by each party and a third arbitrator to be appointed by the first two named arbitrators in writing, or, if they cannot agree, within seven (7) days after the date of the appointment of the last appointment of the two arbitrators, by a Judge of the Supreme Court of Alberta. If either party shall refuse or neglect to appoint an arbitrator within fourteen (14) days after the other party shall have appointed an arbitrator, and shall have served a written notice upon the first mentioned party requiring such party to make such appointment, then the arbitrator first appointed shall, at the request of the party that appointed him, proceed to hear and determine the matters in difference as if he were a single arbitrator appointed by both parties for the purpose, and the award or determination which shall be made by the said arbitrators or the majority of them or by the said arbitrator shall be final and binding upon the parties hereto. In all other respects the provisions of The Arbitration Act of the Province

of Alberta, or any act passed in amendment thereof or substitution therefor, shall apply to each such submission. Operations under this contract shall continue, without prejudice, during the pendency of such arbitration.

ARTICLE VIII - INTERPRETATION

This contract shall be construed and enforceable in accordance with the laws of the Province of Alberta.

ARTICLE IX - CONDITIONS

This agreement and the rights and obligations of the parties hereunder are subject to the parties procuring all permits, certificates and other authorizations required under applicable laws and regulations for their respective purposes and to all present and future laws, regulations and orders of duly constituted authorities having jurisdiction in the premises.

ARTICLE X - NOTICES

Every request, notice, and appointment provided for in this Agreement shall be directed to the party to whom the same is to be made, given or delivered and shall be sufficiently made, given or delivered if mailed by fully pre-paid registered post in an envelope addressed to such party as follows:

Gas Company: The Secretary,
Alberta and Southern Gas Co. Ltd.,
Natural Gas Building,
140 Sixth Avenue S.W.,
Calgary, Alberta.

Alberta Utilities: Canadian Western Natural Gas Company Limited, and
Northwestern Utilities, Limited,
c/o The Secretary,
Canadian Western Natural Gas Company Limited,
Natural Gas Building,
140 Sixth Ave. S.W.,
Calgary, Alberta.

or if delivered by hand to the Secretary for the time being of Alberta and Southern Gas Co. Ltd. for Gas Company and to the Secretary for the time being of Canadian Western Natural Gas Company Limited for Alberta Utilities. Such request, notice, or appointment, if mailed as aforesaid shall be deemed to have been made, given or delivered on the day next following two clear days after the day on which the same shall have been so mailed in a post office in either the city of Calgary or the city of Edmonton. Any party may change its address by written notice to the other party.

ARTICLE XI - ASSIGNMENT

This agreement shall bind and inure to the respective successors and assigns of the parties hereto, but no assignment by

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any party hereto shall be effective without the written consent of all other parties hereto.

IN WITNESS whereof this agreement has been executed by the parties as of the day and year first above written.

ALBERTA AND SOUTHERN GAS CO. LTD.

By ______________________________
Its Attorney.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

By ______________________________

By ______________________________

NORTHWESTERN UTILITIES, LIMITED

By ______________________________

By ______________________________

Canadian Western Natural Gas Company Limited

Annual Report

1956

Forty-fifth
ANNUAL REPORT

For the Year ended December 31, 1956

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Calgary, Alberta

Highlights in Review

	1956	1955	1954	1953	1952	1947
Customers at Year End	**68,967**	63,787	58,444	54,690	50,622	34,532
Natural Gas Sales (thousands of cubic feet)	**36,593,469**	34,435,552	31,077,524	28,313,300	26,632,554	18,182,988
Revenue from Sale of Gas	**$ 9,911,674**	$ 9,207,750	$ 8,322,333	$ 7,374,947	$ 6,396,441	$ 3,746,767
Net Income	**$ 1,276,559**	$ 1,209,936	$ 1,042,942	$ 730,653	$ 576,955	$ 476,104
* Annual Gross Additions to Plant	**$ 5,678,453**	$ 3,097,771	$ 2,252,637	$ 2,301,997	$ 2,094,694	$ 624,862
Miles of Pipeline	**1,422**	1,225	1,093	1,050	1,004	730
Maximum Daily Demand (thousands of cubic feet)	**197,215**	183,867	167,354	155,086	150,697	77,661
Communities Served	**49**	36	28	27	25	16
Population Served	**263,000**	242,000	222,000	192,000	188,000	125,000

* Ten Year Total—
Gross Additions to Plant, $24,219,131

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

REGISTERED OFFICE: 140 SIXTH AVENUE WEST
CALGARY, ALBERTA, CANADA

BOARD OF DIRECTORS

A. G. Baalim	R. C. McPherson	F. A. Smith
Howard Butcher, III	P. D. Mellon	F. Stapells
H. W. Francis	H. R. Milner, Q.C.	H. E. Timmins
B. F. Willson	D. K. Yorath	

OFFICERS

H. R. Milner, Q.C.	Chairman of the Company
D. K. Yorath	President
R. C. McPherson	Senior Vice-President
F. A. Smith	Vice-President Finance
B. F. Willson	Vice-President Operations
K. L. MacFadyen	Comptroller
H. M. Hunter	General Manager
H. S. Greenway	Secretary
W. L. McPhee	Treasurer
A. J. Smith	Assistant Secretary
J. H. Miller	Assistant Treasurer

TRANSFER AGENTS

Canadian Western Natural Gas Company Limited
Calgary, Alberta

Crown Trust Company
Montreal 1, Quebec — Toronto 1, Ontario

REGISTRAR

Crown Trust Company
Calgary, Alberta
Montreal 1, Quebec — Toronto 1, Ontario

AUDITORS

Peat, Marwick, Mitchell & Co.
Room 508, 309 Eighth Avenue West, Calgary, Alberta, Canada

Forty-fifth Annual Report of the Directors

To the Shareholders:

Another year of substantial growth and progress was completed December 31, 1956.

GAS SALES AND WEATHER FACTOR: The Company's sales of natural gas have shown an increase from year to year as the number of connected customers has continued to grow. Actual sales amounted to a record 36.6 billion cubic feet, an increase of 6.3 percent over the previous year. Substantial quantities of the Company's sales are for heating requirements. These sales vary directly with temperature. Therefore, it is customary for statistical purposes to convert our actual sales to what they would have been if the weather had been normal. The year's actual average temperature was colder than normal although not as cold as the preceding year. Our estimates show that sales were increased by $387,000 in 1956 and $525,000 in 1955 because of colder than normal weather.

Gross revenue from gas sold amounted to $9,911,674 compared with $9,207,750 the previous year, an increase of $703,924 or 7.6 percent. On the basis of normal temperatures this increase would have been 9.7 percent.

The net income of $1,276,559 was an increase of $66,624 over the previous year. The Company's assets at the year end, excluding intangibles, were in excess of $34,000,000.

GAS SUPPLY: From the "Highlights" on page 2, you will see that a new maximum daily demand was experienced in excess of 197 million cubic feet. Each year as new customers are added the resultant increase in the daily demand gives rise to the need of continuously securing new sources of gas supply. Canadian Western is now served mainly by Turner Valley and Jumping Pound fields, augmented at times of peak from our Foremost field and our storage field at Bow Island. Natural gas from the Nevis area which was contracted for in 1956 now supplies the towns between Red Deer and Calgary. A further source or sources of supply must be obtained in the near future. In addition to the studies made by our own technical staff, Mr. Ralph E. Davis, our consulting geologist, has been engaged in a study of the Company's gas supply requirements and will be submitting his report and recommendations shortly.

PLANT EXPANSION: Historically the year 1956 was one of record expansion for the Company. That the whole programme was successfully completed before winter was due to favorable weather and the efficient organization and operation of the Company's construction crews. During the year the number of customers increased by some 5,180, bringing the total to 68,967. Thirteen new communities were connected, including those between Red Deer and Calgary. A large Royal Canadian Air Force training establishment near Penhold, just south of Red Deer, and a sugar beet factory at Picture Butte, are among our new customers.

The six-storey addition to the head office building in Calgary will be completed and occupied before the summer of 1957. This structure, faced with maroon porcelain enamel panels, is a distinctive addition to the increasingly imposing skyline of the city of Calgary.

The gross capital additions for the year amounted to $5,678,453. It is anticipated that capital additions for 1957 will exceed $3,000,000.

FINANCING: In early February 1957, $7,000,000 of 5¾% First Mortgage Sinking Fund Series B Bonds were sold to the public. The proceeds of this issue were applied in part to liquidate $4,500,000 of short term loans payable by the Company. The balance will be available to finance in part, the current expansion program of the Company.

RATES: Other than the introduction of suitable rates for the new towns and communities added to our system, existing rates have remained stable for a number of years. The Company's rates for natural gas are among the lowest on the North American continent. It appears, however, that the increasing costs of capital additions and of rendering service to customers, coupled with the higher costs of financing, plus the need of connecting new sources of gas supply, may affect the Company's earnings adversely. In such an event the Company may have no alternative but to seek an increase in the rates it charges its customers.

AUTOMATION: In the interest of increased efficiency and economy, automation has replaced the former method of billing customer accounts. A system using mark sense meter reading

cards and tabulating equipment was put into operation during 1956. As the operating techniques are mastered by our staff, other routines will be converted to punch card records.

EXECUTIVE: Considerable reorganization of the Company's staff was undertaken during the year. Some of the new appointments are shown in the list of Officers of the Company on page 3, such as Mr. D. K. Yorath as President, Mr. R. C. McPherson as Senior Vice-President, Mr. F. A. Smith as Vice-President Finance, Mr. B. F. Willson as Vice-President Operations, Mr. H. M. Hunter as General Manager, and Mr. K. L. MacFadyen as Comptroller. Mr. J. A. Fleming, an experienced natural gas utility man, has been engaged as Director of Public Relations.

The firm of Stone & Webster Service Corporation has been engaged to study our operations and furnish consulting services on certain special projects.

PUBLIC and PERSONNEL RELATIONS: We have always taken pride in the good relations which exist with our customers and the public generally.

We recently completed a colored moving picture of our operations entitled "Meet Your Gas Company." Already it has been shown to many organizations throughout Alberta. It tells the story of the production, transportation and distribution of natural gas by this Company and its associate. Should any group of shareholders care to view this film the Company will be glad to make it available to them.

Good public relations cannot be maintained without good employee relations. The friendly association which exists between the management and employees of this Company is something of which both can be proud.

Our group welfare plans are under continuous review and from time to time are revised to keep pace with the trend in industry on this continent. In 1956 both the Group Life and Pension plans have been amended to provide better coverage in case of death and more adequate pensions for those reaching retirement age. Our Accident and Sickness benefit plan is most comprehensive and is extended to an employee's dependents. All three of these plans are on a contributory basis.

An Employees' Association with an elected council, co-ordinates certain functions of the staff such as social, sport and recreational activities which are encouraged by the Company and are very capably arranged and operated by this Association. Employee-Management matters concerning Company policy are dealt with efficiently and harmoniously through this Association.

A total of 430 permanent employees are on the payroll. This number is greatly augmented during our construction programme by the employment of a large number of temporary employees.

We are proud of those who have devoted a major portion of their lives to service with our Company. Long Service Awards have been given as follows:

40 years	5 employees
30 years	31 employees
20 years	148 employees

The Directors of the Company once again express appreciation of the continued support and confidence of our shareholders, and our customers. The Board thanks the officers and the employees for the efficient manner in which they meet and keep pace with the growth of the communities we serve.

By Order of the Board of Directors,

D. K. Yorath

President

Calgary, Alberta
February 27, 1957.

Canadian Western Nat

BALANCE SHEET a

(with comparative figures fo

ASSETS	1956	1955
Fixed assets:		
Property, plant, gas wells and equipment—at cost	$31,522,730	$26,250,079
Undertaking, franchises, gas rights, etc., in respect of which no provision for amortization is being made (including $2,000,000 par value ordinary shares in Calgary Gas Company, Limited) acquired through issue of 80,000 ordinary shares	8,000,000	8,000,000
	39,522,730	34,250,079
Investments not having market quotations—at cost, less reserve	37,567	35,109
Current assets:		
Cash	279,713	623,189
Accounts receivable:		
Consumers' gas accounts and other accounts (including $75,000 of unbilled revenue which is less than estimated) less allowance for doubtful accounts	1,153,200	1,110,363
Advances to officers and employees for expenses	4,147	3,508
Due from affiliated companies	38,235	6,361
Materials and supplies—at cost, less estimated deterioration and obsolescence	1,108,908	761,954
Total current assets	2,584,203	2,505,375
Unamortized bond discount and expenses of financing	107,218	119,028
Other prepaid expenses and deferred charges	85,995	25,331
	$42,337,713	$36,934,922

Approved on behalf of the Board:
H. R. MILNER, Director.
D. K. YORATH, Director.

Statement in accordance with Section 109(6) of The Companies Act (Alberta):

Calgary Gas Company, Limited, a subsidiary company, is not an operating company and consequently there are no earnings or deficit to be dealt with in the accounts of the above company.

PEAT, MARWICK, MITCHELL & CO.,
Chartered Accountants.

Gas Company Limited

f *December 31, 1956*

ended December 31, 1955)

LIABILITIES	1956	1955
Funded debt:		
3½% First Mortgage Sinking Fund Bonds, Series A, due April 1, 1971	$ 8,000,000	$ 8,000,000
Less redeemed and cancelled	1,100,000	800,000
	6,900,000	7,200,000
Less purchased for sinking fund	459,000	298,000
	6,441,000	6,902,000
Less payment due within one year	–	2,000
	6,441,000	6,900,000
Notes payable to parent company—due 1958	1,900,000	–
Reserves:		
Amortization and depreciation	8,479,313	7,786,054
Contributions for extensions	109,578	94,309
Miscellaneous	193,081	144,122
	8,781,972	8,024,485
Consumers' deposits	390,050	311,015
Current liabilities:		
Bank loan	2,500,000	–
Demand notes payable to affiliated company	100,000	–
Accounts payable and accrued charges	960,951	745,410
Interest accrued on funded debt	56,359	63,000
Interest accrued on consumers' deposits	46,688	34,261
Due to affiliated company	–	5,224
Sinking fund payment due within one year	–	2,000
Income taxes—estimated, less payments thereon	416,710	523,359
Other taxes	192,912	152,037
Total current liabilities	4,273,620	1,525,291
Capital stock and surplus:		
Cumulative redeemable preference shares 4% series (redeemable at the option of the Company on 30 days' notice at $20.60 per share): Authorized—600,000 shares of a par value of $20.00 each. Issued 275,410 shares of a par value of $20.00 each	5,508,200	5,508,200
Ordinary shares: Authorized and issued—80,000 shares of a par value of $100.00 each	8,000,000	8,000,000
Earned surplus (Note 1)	5,331,330	4,954,390
General reserve	1,711,541	1,711,541
	15,042,871	14,665,931
Total capital stock and surplus	20,551,071	20,174,131
Contractual liabilities (Note 2)		
	$42,337,713	$36,934,922

NOTES TO BALANCE SHEET AS OF DECEMBER 31, 1956

1. Sections 18 and 19 of Article VII of the Trust Deed securing the First Mortgage Bonds place certain restrictions upon the payment of dividends and management fees and upon the redemption of, or repayment of, the Company's preference and ordinary shares.
2. The Company is presently erecting an office building; as of December 31, 1956, there were contractual liabilities relative thereto of approximately $800,000. No liability relative to these contractual liabilities is included in the accompanying financial statements.

Canadian Western Natural Gas Company Limited

Profit and Loss Account

FOR THE YEAR ENDED DECEMBER 31, 1956

(with comparative figures for the year ended December 31, 1955)

	1956	1955
Sales of gas—net	$ 9,911,674	$ 9,207,750
Deduct:		
Natural gas purchased	3,754,442	3,617,113
Operating expenses	2,251,514	1,873,730
Maintenance expenses	424,230	415,438
Directors' fees	4,100	2,685
Taxes—other than income	552,802	505,271
Depreciation—exclusive of $100,321 included in other expenses (1955—$108,348)	616,774	534,565
	7,603,862	6,948,802
Net operating income	2,307,812	2,258,948
Miscellaneous income:		
Interest, dividends and royalties	14,459	38,862
Other—net	–	3,789
	14,459	42,651
	2,322,271	2,301,599
Miscellaneous charges:		
Interest on funded debt	236,182	253,750
Proportion written off bond discount and expenses of financing	11,810	12,275
Interest on long term notes	45,624	–
Consumers' deposit and sundry interest	56,158	13,505
Other—net	3,321	–
	353,095	279,530
Net income before income taxes	1,969,176	2,022,069
Provision for income taxes (Note 1)	692,617	812,133
Net income	$ 1,276,559	$1,209,936

Note 1: Effective January 1, 1954, the company was permitted to claim depreciation at maximum rates for tax purposes without charging such depreciation in its accounts. The company has taken advantage of the change in the income tax regulations and has, thereby, effected a reduction in income tax of approximately $211,000 in 1956, $121,000 in 1955 and a total aggregate of $434,000 to December 31, 1956.

Canadian Western Natural Gas Company Limited

Earned Surplus Account

FOR THE YEAR ENDED DECEMBER 31, 1956

Earned surplus as of December 31, 1955		$4,954,390
Add:		
Profit on sale of capital assets	$ 425	
Unclaimed dividends	284	
Net income for the year ended December 31, 1956	1,276,559	1,277,268
		6,231,658
Deduct:		
Dividends on cumulative redeemable preference shares 4% series	220,328	
Dividends on ordinary shares	680,000	900,328
Earned surplus, December 31, 1956		$5,331,330

AUDITORS' REPORT TO THE SHAREHOLDERS

We have examined the balance sheet of Canadian Western Natural Gas Company Limited as of December 31, 1956, and the statements of profit and loss and surplus for the year ended on that date and have obtained all the information and explanations we have required. Our examination included a general review of the accounting procedures and such tests of accounting records and other supporting evidence as we considered necessary in the circumstances.

In our opinion the accompanying balance sheet and statements of profit and loss and surplus are properly drawn up so as to exhibit a true and correct view of the state of the affairs of the company at December 31, 1956, and the results of its operations for the year ended on that date, according to the best of our information and the explanations given to us and as shown by the books of the company.

PEAT, MARWICK, MITCHELL & CO.,
Chartered Accountants.

Calgary, Alberta
January 31, 1957

Calgary Gas Company, Limited

Subsidiary of

Canadian Western Natural Gas Company Limited

Balance Sheet

December 31, 1956

ASSETS

Franchise and Rights	$2,000,000

SHARE CAPITAL

Authorized and Issued:	
20,000 ordinary shares of $100 each	$2,000,000

Approved on behalf of the Board:

H. R. MILNER, Director.

D. K. YORATH, Director.

AUDITORS' REPORT TO THE SHAREHOLDERS

We have examined the accounts of Calgary Gas Company, Limited, for the year ended December 31, 1956, and we have to report that we have obtained all the information and explanations we have required and, in our opinion, the above Balance Sheet as of December 31, 1956, is properly drawn up so as to exhibit a true and correct view of the state of the company's affairs at December 31, 1956, according to the best of our information and the explanations given to us and as shown by the books of the company.

PEAT, MARWICK, MITCHELL & CO.,
Chartered Accountants.

Calgary, Alberta
January 31, 1957.

Combined Statistical Data Relating to Alberta's Major Associated Natural Gas Utility Companies

Canadian Western Natural Gas Company Limited, Calgary
Northwestern Utilities, Limited, Edmonton

	1956	1955	1954	1953	1952	1947
Customers at Year End	**138,975**	128,942	118,798	110,388	100,883	61,816
Natural Gas Sales (thousands of cubic feet)	**80,879,031**	74,029,788	64,233,632	54,024,869	50,548,768	28,699,281
Revenue from Sale of Gas	**$20,554,122**	$18,835,027	$16,743,710	$14,225,640	$12,822,063	$ 6,187,982
Net Income	**$ 3,362,043**	$ 3,130,937	$ 2,801,934	$ 1,787,872	$ 1,739,709	$ 1,123,320
* Annual Gross Additions to Plant	**$11,120,818**	$ 6,221,482	$ 5,919,611	$ 6,972.549	$ 5,583,373	$ 2,515,041
Miles of Pipeline	**3,254**	2,830	2,613	2,445	2,230	1,433
Maximum Daily Demand (thousands of cubic feet)	**438,927**	409,604	358,515	307,535	297,679	152,160
Communities Served	**93**	68	57	54	50	28
Population Served	**557,000**	511,000	475,000	421,000	397,000	261,000

* Ten Year Total—
Gross Additions to Plant, $62,757,181


Legend
GAS and/or OIL FIELDS
CITIES and TOWNS
EXISTING NATURAL GAS TRANSMISSION LINES
PROPOSED NATURAL GAS TRANSMISSION LINES
SCALE
SYSTEM OF NORTHWESTERN UTILITIES, LIMITED
SYSTEM OF CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
Proposed Alberta Gas Trunk Line
Pipeline owned by others
Trans-Canada Pipe Line
SASKATCHEWAN
BRITISH COLUMBIA
MONTANA
U. S. A.
ATHABASCA OIL SANDS
McMURRAY
PEACE RIVER
WHITELAW
DUNVEGAN
POUCE COUPE
TANGENT
RYCROFT
BELLOY
STURGEON LAKE
WINDFALL
PICARDVILLE
REDWATER
EDMONTON
Hinton
Edson
PEMBINA
LEDUC-WOODBEND
GOLDEN SPIKE
WIZARD LAKE
BONNIE GLEN
MINNEHIK
WESTEROSE
SAMSON
HOMEGLEN - RIMBEY
RED DEER
JOFFRE
NEVIS
ERSKINE
STETTLER
FENN-BIG VALLEY
KESSLER
PROVOST
LLOYDMINSTER
WILDMERE
VIKING - KINSELLA
SUNDRE
WESTWARD HO
HARMATTAN-ELKTON
OLDS
CARBON
DRUMHELLER
WEST DRUMHELLER
SUNNYNOOK
CESSFORD
OYEN
SIBBALD
BINDLOSS
ATLEE BUFFALO
CALGARY
JUMPING POUND
SARCEE
OKOTOKS
TURNER VALLEY
MAZEPPA
COUNTESS
DUCHESS
STEVEVILLE
PRINCESS
BROOKS
SUFFIELD
MEDICINE HAT
BOW ISLAND
ETZIKOM
FOREMOST
MANYBERRIES
PENDANT D'OREILLE
SMITH COULEE
COMREY
BLACK BUTTE
PINCHER CREEK
BANFF NATIONAL PARK
JASPER NATIONAL PARK

Canadian Western Natural Gas Company Limited

Northwestern Utilities, Limited

NATURAL GAS SERVICE

Annual Report

1956

Thirty-Third
ANNUAL REPORT

for the year ended December 31, 1956

NORTHWESTERN UTILITIES, LIMITED
Edmonton, Alberta

HIGHLIGHTS IN REVIEW

	1956	1955	1954	1953	1952	1947
Customers at Year End	70,008	65,155	60,354	55,698	50,261	27,284
Natural Gas Sales (thousands of cubic feet)	44,285,562	39,594,236	33,156,108	25,711,569	23,916,214	10,516,293
Revenue from Sale of Gas	$10,642,448	$ 9,627,277	$ 8,421,377	$ 6,850,693	$ 6,425,622	$ 2,441,215
Net Income	$ 2,085,484	$ 1,921,001	$ 1,758,992	$ 1,057,219	$ 1,162,754	$ 647,216
Annual Gross Additions to Plant*	$ 5,442,365	$ 3,123,711	$ 3,666,974	$ 4,670,552	$ 3,488,679	$ 1,890,179
Miles of Pipeline	1,832	1,605	1,520	1,395	1,226	703
Maximum Daily Demand (thousands of cubic feet)	241,712	225,737	191,161	152,449	146,982	74,499
Communities Served	44	32	29	27	25	12
Population Served	294,000	269,000	253,000	229,000	209,000	136,000

*Ten Year Total—
Gross additions to plant $38,538,050.

NORTHWESTERN UTILITIES, LIMITED

REGISTERED OFFICE 10124 104 STREET
EDMONTON, ALBERTA, CANADA

BOARD OF DIRECTORS

OFFICERS

H. R. Milner, Q.C.	Chairman of the Company
D. K. Yorath	President
R. C. McPherson	Senior Vice-President
F. A. Smith	Vice-President Finance
B. F. Willson	Vice-President Operations
K. L. MacFadyen	Comptroller
M. E. Stewart	General Manager
C. L. Metcalfe	Secretary
J. B. Whelihan	Treasurer
J. E. Roberts	Assistant Secretary
B. T. Banks	Assistant Treasurer

TRANSFER AGENT AND REGISTRAR

Montreal Trust Company

Edmonton, Alberta	Calgary, Alberta
Toronto 1, Ontario	Montreal 1, Quebec

AUDITORS

Peat, Marwick, Mitchell & Co.
413 Empire Block, Edmonton, Alberta, Canada

Thirty-Third Annual Report of the Directors

To the Shareholders:

Another year of substantial growth and progress was completed December 31, 1956.

GAS SALES AND WEATHER FACTOR

The Company's sales of natural gas have shown an increase from year to year as the number of connected customers has continued to grow. Actual sales amounted to a record 44.3 billion cubic feet, an increase of 11.8 per cent over the previous year. Substantial quantities of the Company's sales are for heating requirements. These sales vary directly with temperature. Therefore it is customary for statistical purposes to convert our actual sales to what they would have been if the weather had been normal. The year's actual average temperature was colder than normal although not as cold as the preceding year. Our estimates show that sales were increased by $164,000 in 1956 and $270,000 in 1955 because of colder than normal weather.

Gross revenue from gas sold amounted to $10,642,448 compared with $9,627,277 the previous year, an increase of $1,015,171 or 10.5 per cent. On the basis of normal temperatures this increase would have been 12.0 per cent.

The net income of $2,085,484 was an increase of $164,483 over the previous year. The Company's assets at the year end were nearly $53,000,000.

GAS SUPPLY

From the "Highlights" on Page 2 you will see that a new maximum daily demand was experienced in excess of 241 million cubic feet. Each year as new customers are added the resultant increase in the daily demand gives rise to the need of continuously securing new sources of gas supply. Northwestern is now served from twelve separate sources of supply, the main ones being the Viking-Kinsella, Leduc and Bonnie-Glen fields. A further source or sources of supply must be obtained in the near future. In addition to the studies made by our own technical staff, Mr. Ralph E. Davis, our consulting geologist, has been engaged in a study of the Company's gas supply requirements and will be submitting his report and recommendations shortly.

PLANT EXPANSION

Historically the year 1956 was one of record expansion for the Company. That the whole programme was successfully completed before winter was due to favorable weather and the efficient organization and operation of the Company's construction crews. During the year the number of customers increased by some 4,853, bringing the total to 70,008. Twelve new communities were connected to our own system or served by us from lines owned by others. Among the large industrial customers added were Western Plywood Co. Ltd., American Marietta Co. of Canada Ltd., Alberta Phoenix Tube and Pipe Ltd., Nadon Paving Ltd., and Edmonton Steel Fabricators Ltd.

It is proposed to commence the construction of a new head office building in Edmonton in the Spring of 1957. At the outset five floors and the basement will accommodate us and an associate company. The remaining seven floors will be leased to others. It is anticipated the building will be completed late in 1958.

The gross capital additions in 1956 amounted to $5,442,365. It is anticipated that capital additions in 1957 will exceed $3,000,000.

FINANCING

To assist in the financing of the 1956 capital program, $4,000,000 par value 4% cumulative preference shares were sold in April.

RATES

Other than the introduction of suitable rates for the new towns and communities added to our system, existing rates have remained stable for a number of years. The Company's rates for natural gas are among the lowest on the North American continent. It appears, however, that the increasing costs of capital additions and of rendering service to customers, coupled with the higher costs of financing, plus the need of connecting new sources of gas supply, may affect the Company's earnings adversely. In such an event the Company may have no alternative but to seek an increase in the rates it charges its customers.

AUTOMATION

In the interest of increased efficiency and economy, automation has replaced the former method of billing customer accounts. A system using mark sense meter reading cards and tabulating equipment was put into operation during 1956. As the operating techniques are mastered by our staff, other routines will be converted to punch card records.

EXECUTIVE

Considerable re-organization of the Company's staff was undertaken during the year. Some of the new appointments are shown in the list of Officers of the Company on Page 3, such as: Mr. D. K. Yorath as President, Mr. R. C. McPherson as Senior Vice-President, Mr. F. A. Smith as Vice-President Finance, Mr. B. F. Willson as Vice-President Operations, Mr. M. E. Stewart as General Manager, Mr. K. L. MacFadyen as Comptroller. Mr. J. A. Fleming, an experienced natural gas public utility man, has been engaged as Director of Public Relations.

The firm of Stone & Webster Service Corporation has been engaged to study our operations and furnish consulting services on certain special projects.

PUBLIC AND PERSONNEL RELATIONS

We have always taken pride in the good relations which exist with our customers and the public generally.

We recently completed a colored moving picture of our operations entitled "Meet Your Gas Company." Already it has been shown to many organizations throughout Alberta. It tells the story of the production, transportation and distribution of natural gas by this Company and its associate. Should any group of shareholders care to view this film the Company will be glad to make it available to them.

Good public relations cannot be maintained without good employee relations. The friendly association which exists between the management and employees of this Company is something of which both can be proud.

Our group welfare plans are under continuous review and from time to time are revised to keep pace with the trend in industry on this continent. In 1956 both the Group Life and Pension plans have been amended to provide better coverage in case of death and more adequate pensions for those reaching retirement age. Our Accident and Sickness benefit plan is most comprehensive and is extended to an employee's dependents. All three of these plans are on a contributory basis.

An Employees Association with an elected council, co-ordinates certain functions of the staff such as social, sport and recreational activities which are encouraged by the Company and are very capably arranged and operated by this Association. Employee-Management matters concerning Company policy are dealt with efficiently and harmoniously through this Association.

A total 450 permanent employees are on the payroll. This number is greatly augmented during our construction programme by the employment of a large number of temporary employees.

We are proud of those who have devoted a major portion of their lives to service with our Company. Long Service Awards have been given as follows:

30 years	10 employees
20 years	63 employees

The Directors of the Company once again express appreciation of the continued support and confidence of our shareholders and our customers. The Board thanks the officers and the employees for the efficient manner in which they meet and keep pace with the growth of the communities we serve.

By Order of the Board of Directors

D. K. Yorath

President.

Edmonton, Alberta,
March 1, 1957.

NORTHWESTERN

Balance Sheet as

(with compa

ASSETS

	1956	1955
Fixed Assets:		
Property, plant, leases, rights, gas wells and equipment, including intangibles subject to amortization and depreciation, at cost (of which $517,635 was satisfied by issuance of stock)	$ 48,040,757	$ 42,717,892
Leases, wells, property rights and intangibles not subject to amortization and satisfied by the issuance of stock, less amount written off	338,620	348,620
	48,379,377	43,066,512
Investments not having market quotations, at cost, less reserve	53,295	35,587
Current Assets:		
Cash on hand and in bank	181,074	191,036
Short term investment certificates	1,500,000	1,750,000
Accounts receivable: Consumers' gas and other receivables	1,360,576	1,384,337
Due from affiliated company	14,688	15,942
Advances to officers and employees for expenses	6,259	3,754
Materials and supplies at cost, less estimated deterioration and obsolescence	1,120,198	1,253,324
Total Current Assets	4,182,795	4,598,393
Retroactive increase in rates allowed by The Board of Public Utility Commissioners, less amount written off	—	75,000
Deferred Charges:		
Unamortized bond discount and expenses of financing (including premium, discount and expenses of prior issues retired)	138,045	159,393
Other prepaid expenses and deferred charges	81,678	51,528
	219,723	210,921
	$ 52,835,190	$ 47,986,413

Signed on behalf of the Board:

H. R. MILNER, Director

D. K. YORATH, Director

(This is the balance sheet referred to in the report of Peat, Marwick, Mitchell & Co., Chartered Accountants, dated February 12, 1957)

ecember 31, 1956

es for 1955)

LIABILITIES

		1956	1955
Funded Debt (excluding current maturities) (note 1)		$ 16,771,500	$ 17,524,000
3⅞% Promissory Notes Payable, due September 1, 1969		2,184,000	2,331,000
Less payment due within one year		156,000	147,000
		2,028,000	2,184,000
Reserves:			
Amortization and depreciation of fixed assets		8,992,787	7,753,551
Contributions for extensions		481,063	473,313
Miscellaneous		200,725	153,430
		9,674,575	8,380,294
Consumers' Deposits		464,381	422,699
Current Liabilities:			
Acounts payable and accrued charges		778,316	646,286
Interest accrued on funded debt and notes payable		140,855	146,129
Sinking fund payments due within one year		752,500	673,000
Payment on promissory notes due within one year		156,000	147,000
Due to affiliated companies		38,089	4,818
Income taxes, estimated, less payments		496,660	669,770
Other taxes		435,520	402,561
Total Current Liabilities		2,797,940	2,689,564
Capital Stock and Surplus:			
4% Cumulative preference shares (redeemable at the option of the company on thirty days' notice at $103 per share):			
Authorized—120,000 shares of a par value of $100 each	$12,000,000		
Issued—105,000 shares of a par value of $100 each (40,000 issued for cash in 1956)		10,500,000	6,500,000
Common shares:			
Authorized—300,000 shares of a par value of $25 each	$ 7,500,000		
Issued—170,000 shares of a par value of $25 each		4,250,000	4,250,000
Earned surplus (note 2)		6,348,794	6,035,856
		10,598,794	10,285,856
Total Capital Stock and Surplus		21,098,794	16,785,856
		$ 52,835,190	$ 47,986,413

(See page 8 for notes 1 and 2, which form an integral part of the above balance sheet.)

Notes to Balance Sheet

DECEMBER 31, 1956

(1) Funded Debt:

		1956	1955
First mortgage sinking fund bonds, due December 15, 1971:			
Authorized and issued:			
3½% Series "B"		$ 4,500,000	$ 4,500,000
Less redeemed and cancelled		1,150,000	1,000,000
		3,350,000	3,500,000
3½% Series "C"		2,000,000	2,000,000
Less redeemed and cancelled		462,000	396,000
		1,538,000	1,604,000
3 5/8% Series "D"		5,000,000	5,000,000
Less redeemed and cancelled		985,000	810,000
		4,015,000	4,190,000
First mortgage sinking fund bonds, due December 15, 1975:			
Authorized and issued:			
3 5/8% Series "E"		5,000,000	5,000,000
Less redeemed and cancelled		645,000	480,000
		4,355,000	4,520,000
First mortgage sinking fund bonds 4¾% Series "F" due January 15, 1979:			
Authorized:	$ 5,000,000		
Issued		4,500,000	4,500,000
Less redeemed and cancelled		234,000	117,000
		4,266,000	4,383,000
Total Funded debt less redeemed and cancelled		17,524,000	18,197,000
Less sinking fund payments due within one year		752,500	673,000
Funded debt less current maturities		$ 16,771,500	$ 17,524,000

(2) The 3 7/8% promissory notes and the trust deed securing the first mortgage bonds impose certain restrictions on the payment of dividends and management fees and upon the redemption or repayment of the company's preference and common shares.

Profit and Loss Account

YEAR ENDED DECEMBER 31, 1956
(with comparative figures for 1955)

	1956	1955
Sales of Gas (net)	$ 10,642,448	$ 9,627,277
Deduct amount of retroactive increase in rates presumed to be recovered	75,000	75,000
	10,567,448	9,552,277
Deduct Expenses:		
Natural gas purchased	1,377,353	1,065,940
Operating	2,763,442	2,485,829
Maintenance	716,423	525,676
Directors' fees	4,600	3,540
Salaries of directors and executive officers	122,560	86,153
Legal fees and disbursements	6,911	8,277
Taxes other than income tax	777,557	706,329
Depreciation exclusive of $106,482 included in operating and other accounts (1955—$116,806)	1,131,184	1,050,794
	6,900,030	5,932,538
Net Operating Income	3,667,418	3,619,739
Miscellaneous Income:		
Interest and dividends	93,511	59,457
Other	83,654	58,619
	177,165	118,076
	3,844,583	3,737,815
Miscellaneous Charges:		
Interest on funded debt and notes	778,501	808,076
Proportion written off bond discount, premium and expenses, etc.	21,348	21,348
Premium on bonds redeemed	3,750	3,750
	803,599	833,174
Net Income before Income Tax	3,040,984	2,904,641
Provision for Income Tax (note)	955,500	983,640
Net Income	$ 2,085,484	$ 1,921,001

NOTE: Effective January 1, 1954, the company was permitted to claim depreciation at maximum rates for tax purposes without charging such depreciation in its accounts. The company has taken advantage of the change in the income tax regulations and has, thereby, effected a reduction in income tax of approximately $240,000 in 1956, $198,000 in 1955 and a total aggregate of $658,000 to December 31, 1956.

NORTHWESTERN UTILITIES, LIMITED

Statement of Earned Surplus

YEAR ENDED DECEMBER 31, 1956

Earned Surplus December 31, 1955		$ 6,035,856
Add net income year ended December 31, 1956		2,085,484
		8,121,340
Deduct:		
Expenses relating to issuance of 4% cumulative preference shares:		
Commissions	$ 390,000	
Expenses	16,146	406,146
		7,715,194
Deduct dividends paid:		
4% cumulative preference shares	346,400	
Common shares	1,020,000	1,366,400
Earned Surplus, December 31, 1956		$ 6,348,794

AUDITORS' REPORT TO THE SHAREHOLDERS

We have examined the balance sheet of Northwestern Utilities, Limited as of December 31, 1956, and the statements of profit and loss and surplus for the year ended on that date and have obtained all the information and explanations we have required. Our examination included a general review of the accounting procedures and such tests of accounting records and other supporting evidence as we considered necessary in the circumstances.

In our opinion the accompanying balance sheet and statements of profit and loss and surplus are properly drawn up so as to exhibit a true and correct view of the state of the affairs of the company at December 31, 1956, and the results of its operations for the year ended on that date, according to the best of our information and the explanations given to us and as shown by the books of the company.

PEAT, MARWICK, MITCHELL & CO.,
Chartered Accountants.

Edmonton, Alberta.
February 12, 1957.

COMBINED STATISTICAL DATA

RELATING TO

Alberta's Major Associated Natural Gas Utility Companies

NORTHWESTERN UTILITIES, LIMITED, EDMONTON

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED, CALGARY

	1956	1955	1954	1953	1952	1947
Customers at Year End	**138,975**	128,942	118,798	110,388	100,883	61,816
Natural Gas Sales (thousands of cubic feet)	**80,879,031**	74,029,788	64,233,632	54,024,869	50,548,768	28,699,281
Revenue from Sale of Gas	**$20,554,122**	$18,835,027	$16,743,710	$14,225,640	$12,822,063	$ 6,187,982
Net Income	**$ 3,362,043**	$ 3,130,937	$ 2,801,934	$ 1,787,872	$ 1,739,709	$ 1,123,320
Annual Gross Additions to Plant*	**$11,120,818**	$ 6,221,482	$ 5,919,611	$ 6,972,549	$ 5,583,373	$ 2,515,041
Miles of Pipeline	**3,254**	2,830	2,613	2,445	2,230	1,433
Maximum Daily Demand (thousands of cubic feet)	**438,927**	409,604	358,515	307,535	297,679	152,160
Communities Served	**93**	68	57	54	50	28
Population Served	**557,000**	511,000	475,000	421,000	397,000	261,000

*Ten Year Total—
Gross additions to plant $62,757,181.


Legend
GAS and/or OIL FIELDS
CITIES and TOWNS
EXISTING NATURAL GAS TRANSMISSION LINES
PROPOSED NATURAL GAS TRANSMISSION LINES
SCALE
SYSTEM OF NORTHWESTERN UTILITIES, LIMITED
NATURAL GAS
Proposed Alberta Gas Trunk Line
Trans-Canada Pipe Line
Pipeline owned by others
SASKATCHEWAN
BRITISH COLUMBIA
U. S. A.
MONTANA
ATHABASCA OIL SANDS
McMURRAY
PEACE RIVER
WHITELAW
DUNVEGAN
POUCE COUPE
TANGENT
RYCROFT
BELLOY
STURGEON LAKE
WINDFALL
PICARDVILLE
REDWATER
FAIRYDELL-BON ACCORD
ALEXANDER
Legal
MORINVILLE
Onoway
St. Albert
EDMONTON
ACHESON
GOLDEN SPIKE
FORT SASKATCHEWAN
BEAVERHILL LAKE
Josephburg
Mundare
Vegreville
Vermilion
LLOYDMINSTER
WILDMERE
VIKING - KINSELLA
Viking
Wainwright Army Camp
LEDUC-WOODBEND
WIZARD LAKE
BONNIE GLEN
JOARCAM
Camrose
Wetaskiwin
SAMSON
WESTEROSE
MINNEHIK
PEMBINA
Wildwood
Edson
Hinton
JASPER NATIONAL PARK
HOMEGLEN - RIMBEY
Ponoka
Morningside
NEVIS
ERSKINE
STETTLER
KESSLER
PROVOST
JOFFRE
RED DEER
Penhold
Rocky Mt. House
FENN-BIG VALLEY
SUNDRE
WESTWARD HO
HARMATTAN ELKTON
OLDS
CARBON
DRUMHELLER
WEST DRUMHELLER
SUNNYNOOK
OYEN
CESSFORD
SIBBALD
BANFF NATIONAL PARK
CALGARY
Forest Lawn
JUMPING POUND
SARCEE
OKOTOKS
Okotoks
TURNER VALLEY
MAZEPPA
COUNTESS
STEVEVILLE
PRINCESS
DUCHESS
BROOKS
Brooks
ATLEE BUFFALO
BINDLOSS
SUFFIELD
MEDICINE HAT
Nanton
SAVANNA CREEK
BOW ISLAND
ETZIKOM
MANYBERRIES
FOREMOST
PENDANT D'OREILLE
SMITH COULEE
COMREY
BLACK BUTTE
PINCHER CREEK

Northwestern Utilities, Limited